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Reference Guideline for Industrial Boiler Manufacturers to Control Pollution with Combustion Modification

KVB, Inc, Tustin, Calif

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REFERENCE GUIDELINE FOR INDUSTRIAL BOILER MANUFACTURERS TO CONTROL POLLUTION WITH COMBUSTION MODIFICATION

Guidelines intended for use as a reference source by:

- industrial boiler equipment manufacturers for pollution control on existing and new boilers
- service organizations responsible for coordinating industrial pollution control activities
- architects and engineers responsible for boiler specifications
- personnel responsible for pollution testing and control
- personnel responsible for air quality management and planning

U.S. ENVIRONMENTAL PROTECTION AGENCY
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16. ABSTRACT The report describes combustion modification methods that are available to boiler manufacturers for controlling air pollutant emissions from industrial size fossil-fuel-fired steam boilers. The methods discussed include reduction of excess air, staged combustion, air register adjustment, fuel oil atomization, combustion air temperature adjustment, flue gas recirculation, burner heat release rate, fuel type, burner tune-up, and ammonia injection. The report summarizes results of tests on specific industrial boilers and discusses the applicability of combustion modifications. Specific guidelines for boiler design to achieve specified emission levels could not be given because of the variability in emissions and responsiveness to control among the various industrial boiler types.

17. KEY WORDS AND DOCUMENT ANALYSIS

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Air Pollution	Dust	Air Pollution Control	13B	11G
Efficiency	Smoke	Stationary Sources	14B	
Combustion	Carbon Monoxide	Industrial Boilers	21B	
Boilers	Sulfur Oxides	Combustion Modification	13A	
Burners	Fossil Fuels	Particulates		21D
Nitrogen Oxides	Natural Gas	Boiler Design	07B	
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SECTION 1.0

INTRODUCTION

This manual is the second of two manuals on industrial boiler emissions controls. The first manual (Ref. 1) was directed to boiler operators and contains recommended procedures for improving boiler performance by methods available to boiler operators. The purpose of this second manual is to describe current combustion modification techniques that are available to boiler manufacturers for controlling air pollutant emissions from industrial-size fossil-fuel-fired steam boilers. The main emphasis will be placed on controlling emissions of oxides of nitrogen (NO_x) from gas, oil and coal fired boilers in the size range 10,000 to 500,000 lb/hr steam.* However, the impact of these techniques on efficiency and on other combustion-generated pollutant emissions (such as particulates and carbon monoxide) that may be affected by NO_x control will also be discussed.

Recent estimates of the NO_x contribution from the industrial boiler size category range from 18 to 28% of the national total for stationary sources (Refs. 2, 3, 4). Increased emphasis on control of stationary source emissions is anticipated and may result in requiring further controls on industrial boilers.

The pollution control methods covered in this manual can be placed into three classes according to the complexity of their application:

- change operating parameters of existing boilers
- retrofit combustion modifications to existing boilers
- incorporate advanced pollution control designs into new boilers

This manual will define the concepts of low-NO_x combustion modifications. These concepts then can be used as basic guideposts for their application in hardware design. Each individual method of combustion modification may not

*It is the policy of the U.S. Environmental Protection Agency to use the metric (SI) system of units. However, for the purposes of this report, English units were considered necessary. For those who prefer metric units, a conversion table is provided in Section 9.0.

find wide applicability for all boiler types in the industrial category. For this reason, control techniques should be reviewed on a unit-by-unit basis.

A significant amount of data has been collected on the various control techniques and they are reported in detail in a number of publications (Refs. 2 and 5-10). These studies cover both field investigation and smaller-scale laboratory work. The discussion in this manual will draw heavily from these studies.

Certain control techniques have not been tried on industrial-size boilers; this is the case for flue gas recirculation (FGR) on pulverized coal (PC) firing. In these instances, guidance can be obtained from large utility boiler studies; where, for example, it has been shown that FGR is not a viable NO_x control technique on PC units (Ref. 11).

Emissions of NO_x are expressed in this manual as concentrations on a dry basis (that is, moisture-free flue gas) corrected to 3% excess O_2. This correction eliminates the effect of dilution of the flue gas by excess air. The measured concentration, $(NO_x)_m$ is converted to the value at 3% O_2 using the formula

$$(NO_x)_{3\%} = (NO_x)_m \times \frac{18}{21 - O_2}$$

where O_2 is measured oxygen concentration in volume percent on a dry basis. If the measurement of NO_x is on a wet basis, the value must first be corrected to a dry basis as discussed in Appendix A.

The purpose of performing the correction to 3% O_2 is to provide a more meaningful way of comparing emissions at different levels of excess air. It is important to understand the difference between the above procedure for correcting NO_x to a common level of excess air and the actual effect that changing excess air has on NO_x emissions. For instance, burning a high-nitrogen heavy oil with 7% excess oxygen might produce a measured level of NO_x of 390 ppmV. Correction of this value to 3% O_2 results in 501 ppmV. An actual reduction of excess air to 3% O_2 might result in NO_x emissions of 425 ppmV. This value is higher than that actually measured at 7% O_2; but when compared with the value of 501 ppm that was corrected for dilution, it is seen that NO_x was actually lower at the lower O_2 condition, and NO_x emission per unit heat input was reduced by lowering excess O_2.

SECTION 2.0

SOURCES OF COMBUSTION POLLUTANTS

2.1 OXIDES OF NITROGEN

The oxides of nitrogen (NO_x) emitted by boilers are mostly nitric oxide (NO) with a few percent of nitrogen dioxide (NO_2). Nitric oxide is colorless whereas nitrogen dioxide is reddish brown. However, NO_2 is seldom present in large enough concentrations to be visible in a boiler stack plume.

Ambient air quality standards are set in terms of NO_2 concentrations only. However, both NO and NO_2 need to be controlled from emission sources because NO is converted fairly rapidly to NO_2 in the atmosphere.

Oxides of nitrogen emissions arise from two sources in a flame:

- thermal fixation of atmospheric N_2 (Thermal NO_x)
- conversion of fuel bound nitrogen (if present) (Fuel NO_x)

The NO_x, once formed, is "frozen" above its chemical equilibrium concentration in the flue gas because there are no available kinetic routes that can destroy it within the residence time between the flame and stack exit.

The formation of thermal NO_x is determined by highly temperature-dependent chemical reactions, the so-called Zeldovich reactions:

$$N_2 + O \rightarrow NO + N$$
$$N + O_2 \rightarrow NO + O$$

The rate of these reactions is significant only at high temperatures (greater than 3000 °F) and doubles for every 70 °F increase in flame temperature. At these temperatures, the rate of formation increases with the square root of

the O_2 concentration except in a small region of the flame where oxygen atoms (O) are present in super-equilibrium amounts. In these regions, the initial rate of formation of NO is higher.

Natural gas, potentially a very clean fuel, can produce well over 1,200 parts per million by volume (ppmV) of thermal NO_x in a boiler with air preheat. This occurs when the fuel is intensively mixed and burned completely before much heat loss or much dilution by cooled combustion products has occurred within the furnace. Oil and coal typically give thermal NO_x concentrations between 60 and 210 ppmV.

The nitrogen contained in fuels such as distillate oil, residual oil and coal may be partially converted to NO_x during combustion. If completely converted to nitric oxide, one percent by weight nitrogen will produce about 1300 ppmV of NO_x in oil firing and roughly 2100 ppmV in coal firing. The difference between the two is mainly due to the lesser heating value of coal. Both fuels produce roughly the same volume of flue gas per million Btu. But for coal more pounds of fuel, and thus more pounds of bound nitrogen, must be burned to liberate a million Btu's. The theoretical maximum flue gas content of NO from fuel nitrogen conversion is therefore higher for a lower-Btu fuel of the same nitrogen content.

The maximum possible NO levels from fuel nitrogen conversion are listed below for some typical fuels of interest.

Fuel	Typical N content, weight percent	Fuel-derived NO (100% conversion), ppmV
Natural gas	0	0
No. 6 oil	0.3	390
Bituminous coal	1.4	2940

Fortunately, conversion of all fuel bound nitrogen seldom occurs. (Values of 25 to 50% are typical for coal and No. 6 oil in normal operation.) Also, this conversion is not nearly as temperature-sensitive as the thermal formation process. The fractional amount of fuel nitrogen converted is greatly influenced by the amount of oxygen which is available when the fuel

molecule decomposes. If the surrounding atmosphere is fuel-rich, the fuel molecule will crack and much of the nitrogen will form N_2. On the other hand, if O_2 is available then a large percentage of the N in the fuel will form NO_x. Theoretical analyses indicate that the percent conversion of fuel N to NOx decreases as the ratio N/O_2 increases and as the temperature decreases. (The dependence on temperature is slight.)

High fuel volatility and intensive fuel-air mixing also encourage conversion of fuel N to NO_x. Conversion to NO_x can range from 10% to over 99%. In residual oil- and coal-fired boilers, 10% to 60% conversion has been observed.

Many regulations set NO_x limits based on pounds of NO_x as NO_2 per million Btu and fuel nitrogen content can be converted to this basis. Assuming complete conversion of fuel nitrogen to NO_x and taking, for example, a coal of 1.4% nitrogen content with a heating value of 13,500 Btu/lb, the N content can be expressed as

$$\frac{1.4 \text{ lb N}}{100 \text{ lb coal}} \times \frac{46 \text{ lb } NO_2}{14 \text{ lb N}} \times \frac{1 \text{ lb coal}}{13{,}500 \text{ Btu}} \times \frac{10^6 \text{ Btu}}{\text{million Btu}} = 3.4 \text{ lb } NO_2/\text{million Btu}$$

If the actual conversion were only 50% then the emission rate would be one-half the above value or 1.7 lb/million Btu. This is of course in addition to any thermal NOx generated.

Fuel-N-derived NO_x is normally much more sensitive to excess O_2 than is thermal NO_x. In general, at a given burning rate the higher the burner airflow, the higher the fuel-N-derived NO_x will be. In contrast, thermal NO_x theoretically maximizes at a fuel/air ratio corresponding to about 1% excess O_2. In practice, vaporization, cracking, and mixing play important roles so that the actual excess O_2 for maximum NO_x can not be predicted. However, fuels containing little or no chemically bound nitrogen (natural gas and some oils) often exhibit a maximum in NO_x emissions as excess O_2 is varied. This means that on any given boiler a decrease in

excess O_2 may either increase or decrease NO_x emissions for low nitrogen fuels, depending on where the maximum lies. For fuels with high nitrogen contents a reduction in excess O_2 nearly always produces a reduction in NO_x.

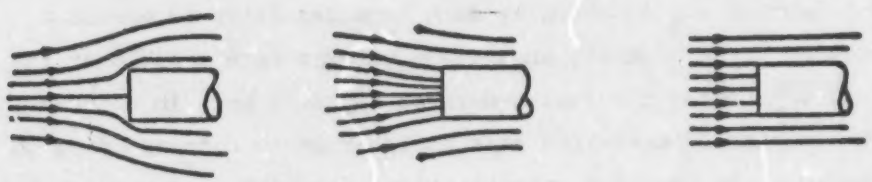
2.2 POLLUTANTS OTHER THAN NO_x

Particulates, sulfur oxides, and smoke are the boiler emissions other than NO_x which are most generally limited by regulations. Carbon monoxide and unburned hydrocarbons are also of interest, although their concentrations are seldom high in a well-tuned boiler.

2.2.1 Particulates

In the EPA Method 5 particulates determination (Ref. 12), the particulates content of the flue gases is determined by sampling isokinetically and passing the sample through a probe to a heated filter. Afterwards the probe is rinsed with acetone. The acetone is boiled off and the weight of the probe washings and the weight gain of the filter are added. This weight is then divided by the fuel heat release represented by the volume of sampled flue gas to obtain the emissions in lb/million Btu.

Isokinetic sampling means drawing the sample into the probe without changing the velocity of the gas. In this way the streamlines are not disturbed (see sketch below).



a. Overspill b. Underspill c. Isokinetic sampling

If the streamlines were disturbed, the sample would not represent the true particulates content of the flue gas. With too low a sampling rate (overspill), too many large heavy particles would be captured because their

high inertia would to some extent prevent their being spilled along with the gases. With too high a sampling rate, on the other hand, not enough of the large, heavy particles would be captured per unit of gas sampled. However, there is less error from using a sampling rate which is too high, than a rate which is too low.

Although EPA Method 5 is widely used, local regulations may require different methods of determining particulates. In some localities, for example, sulfuric acid mist is included with particulates.

When EPA Method 5 is used, the two most important sources of particulates are (a) ash and (b) unburned condensed-phase combustibles like char, soot, tar, or unburned oil or coal particles. (Occasionally, bits of corroded metal from the boiler or heavy dust loading in the inlet air can cause high particulates readings.)

Particulates emissions in gas firing are usually negligible. When firing heavy oil in a well-tuned boiler, combustible particulates are often of the order of 0.05 lb/million Btu, but can range from 0.01 to 0.05 lb/million Btu. If the particulates limit is 0.10 lb/million Btu, then the ash content of the oil must usually be kept lower than 0.05 lb/million Btu (about 0.1% ash in oil) so that the total of ash and combustibles is below 0.10 lb/million Btu. In oil firing, virtually all of the ash is emitted.

2.2.2 Smoke

A very small amount of unburned combustible in the flue gases can produce a noticeable opacity in the stack plume. The presence of a visible plume does not necessarily mean that particulates concentrations is above 0.10 lb/million Btu.

Official opacity measurements by EPA Method 9 (Ref. 12) must be made visually by an observer who has taken a training course and passed a certification test. Recertification of an observer is required every six months.

A typical opacity limitation is a maximum of 20% steady-state, with a 40% maximum for no more than two minutes in any one hour.

Opacity depends on many variables such as size of particles, NO_2 content, weather conditions, precise time of observation while smoke fluctuates, etc. The best way to avoid protracted debates over the accuracy of opacity measurements is to ensure that the boiler emits no visible smoke.

2.2.3 Carbon Monoxide (CO)

Carbon monoxide emissions from a well-tuned boiler are normally negligible. However, some adjustments which reduce NO_x emissions have a tendency to increase CO emissions, and the latter can be a sensitive indicator of how far to go in reducing NO_x. The following levels are of interest as rough guides:

CO, ppmV dry @ 3% O_2	CO, volume percent, dry @ 3% O_2	
0-50	0-0.005	Usual range for normal operation
100-200	0.1-0.2	Good level for minimum NO_x; CO may increase very rapidly if O_2 is lowered further
400	0.5	Lower limit of resolution of some control-room instruments. Heat loss due to CO no longer negligible.

2.2.4 Unburned Hydrocarbons

As long as CO emissions are below 400 ppmV, emissions of unburned hydrocarbons from boilers are usually very small: 20 ppmV or less. Normally it is not considered necessary to measure unburned hydrocarbons from a boiler, even during NO_x reduction testing.

2.2.5 Oxides of Sulfur

The total amount of sulfur oxides (SO_x) emitted from the stack is largely determined by the sulfur content of the fuel, although in coal firing some of the sulfur may be retained in the ash.

Sulfur in various coals should be evaluated in terms of mass per unit heating value; a fuel which is low in weight percent sulfur can have high SO_x emissions if its heating value is also low.

The heating values of oils vary less than those of coals, and one percent sulfur in oil produces about 580 ppmV (dry, corrected to 3% excess O_2) of SO_x in the flue gas.

Pipeline quality natural gas in the U.S. gives negligible emissions of SO_x.

Normally about 98 to 99% of the SO_x from fossil-fuel combustion in boilers is emitted as sulfur dioxide (SO_2). However, the remainder is emitted as sulfur trioxide (SO_3), which when combined with the water vapor in the flue gases or the ambient air forms sulfuric acid (H_2SO_4) and its hydrates. Because these have a higher dew point than does water, a persistent sulfur acid mist plume may be observed in cold weather when the SO_3 concentration is high. Sulfuric acid condensation can also contribute to boiler cold-end heat exchange surface corrosion and acid smut fallout.

Sulfur trioxide is formed by oxidation of sulfur dioxide. Some of this oxidation occurs in the flame, and some is due to catalysis by solid materials such as vanadium on boiler tubes in the convective section. For a given fuel, the simplest way to minimize SO_3 formation in both places is to minimize oxygen concentration by operating the boiler with low excess air.

SECTION 3.0

METHODS FOR NO_x CONTROL

Methods for reducing NO_x and other combustion-generated pollutants can be divided into three categories:

1. Changing the fuel or its properties
2. Modifying the combustion system
3. Flue gas cleanup.

This report is mainly concerned with Category 2. The Thermal $DeNO_x$ Process,* described in a later section, might be considered a flue gas clean-up method but it is included in this report because the process is one of selective combustion and takes place only at temperatures well above normal boiler flue gas exit temperatures.

3.1 FUEL TYPE

From the discussion in the previous sections, it is evident that fuels such as natural gas and low-nitrogen oils might be used in place of residual oil and coal to lower NO_x emissions. However, the fuel situation in the U.S. is such that more coal and heavy oil will be used as boiler fuels in the future.

The effect of coal rank on fuel nitrogen conversion is largely unexplored. However, some recent data published (Ref. 13) show that western (U.S.) subbituminous coals have about 15 to 20% lower NO_x emission than eastern bituminous coals with comparable fuel nitrogen contents on a heat-value basis. The difference is believed due to the lower flame temperature associated with the lower heating values and higher moisture contents of the western coals.

*Patented process of the Exxon Corporation.

3.2 EXCESS AIR

A detailed discussion of the effects of excess air on emissions and efficiency is contained in a guideline manual for boiler performance improvement (Ref. 1). That manual contains step-by-step procedures for optimization of excess air.

Figure 1 shows the NO trends of a number of industrial boilers as a function of excess O_2 in the flue gas for natural gas, oil, and coal. Generally, the slopes of the NO versus O_2 lines decrease from coal to oil to gas. This makes excess O_2 control critical in terms of NO_x control for nitrogen-containing fuels.

Some of the curves exhibit a maximum. This results because although the oxygen content of the flue gas increases with increasing excess air, the flame temperature decreases. As a result of these two opposing effects, thermal NO_x emissions pass through a maximum. The fuel-derived NO_x, being rather temperature-insensitive, increases monotonically with increased excess air.

Coal shows the highest sensitivity to excess air, with an average reduction of 50 ppm for each 1% decrease in excess oxygen.

Low-excess-air firing of a boiler requires additional control equipment and instrumentation to monitor emissions; however, this mode of operation generally results in an increase in system efficiency which translates directly into fuel savings. Thermal efficiencies of 77 to 87% are typical of normally operating industrial boilers. A reduction in excess oxygen of 1% will result in an average efficiency improvement of 0.5%. As the price of fuel rises, investment in such improvements becomes more feasible economically.

Low excess air can be an effective NO_x reduction technique for oil and coal, providing that care is taken not to produce excessive amounts of CO and smoke.

A point may be reached where further reductions in excess air will result in severe flame instability. This limit will usually occur in the range of 2 to 5% excess O_2 for pulverized coal and residual oils, 1-3% excess O_2 for distillate oils, and 0.1-0.5% excess O_2 for natural gas.

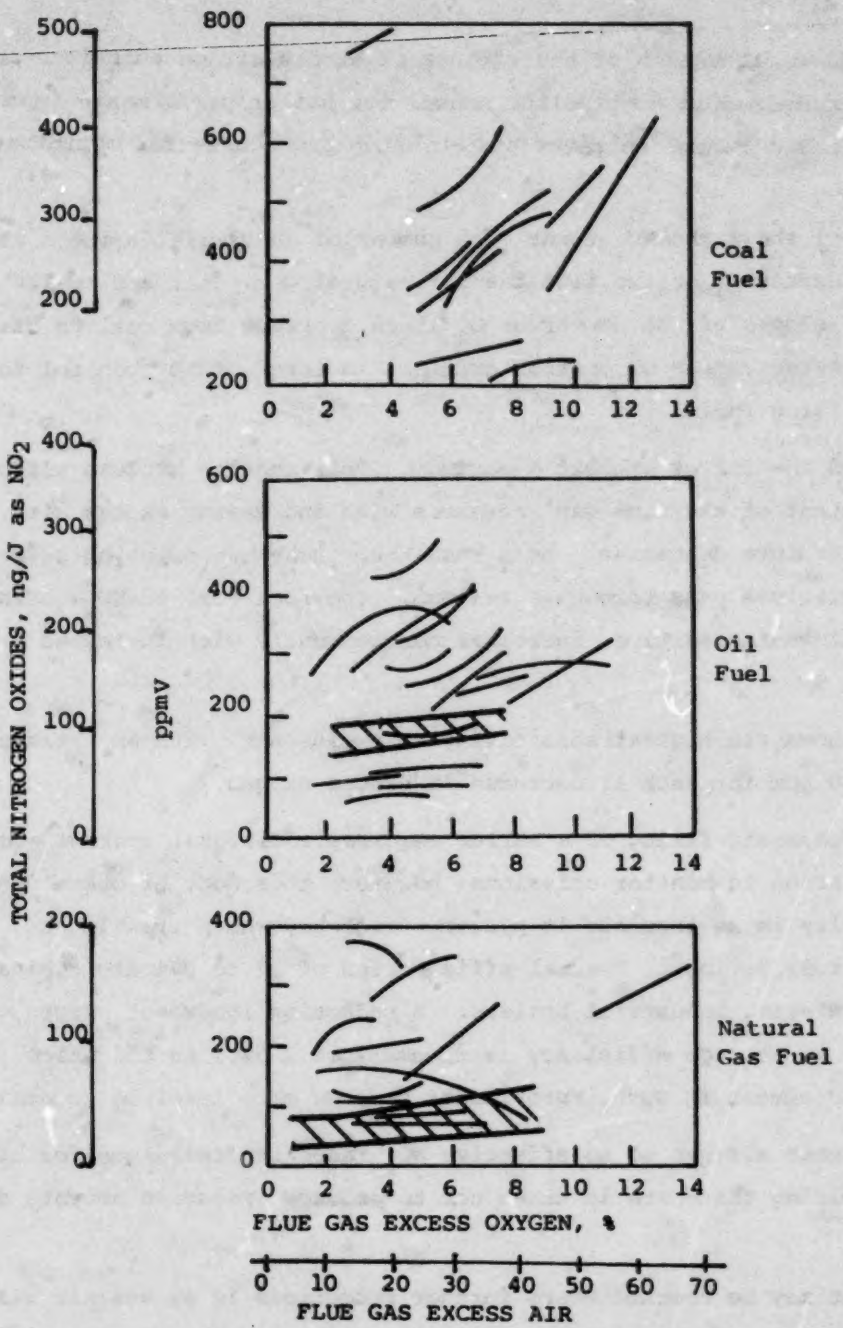


Figure 1. Effect of excess oxygen on nitrogen oxides emissions. Single lines for watertube boilers, shaded areas represent firetube boiler data.

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Low-excess-air firing can be very beneficial from the emissions and efficiency standpoint; however, such systems must also be sophisticated enough that a minimum of operator interaction is required. Oxygen analyzers must be available and properly utilized. It is also important to provide for measurement of combustibles and NO_x.

3.3 STAGED COMBUSTION

Staged combustion involves introducing some of the combustion air into the furnace through overfire air ports (called NO_x ports) or through burners to which the fuel flow has been terminated. The active burners may thus be operated at air-to-fuel ratios which are in some cases well below stoichiometric. The average O_2 concentration and average temperature at the burner are reduced, and this reduces formation rates of both thermal and fuel-N-derived NO_x. Most of the nitrogen-bearing organic molecules are cracked to form N_2 in this first stage.

That part of the fuel which is not completely burned at the burner combines with the air introduced at other points in the furnace to complete the combustion. In this "second-stage" combustion, the temperatures are relatively low because the fuel and air are at this point diluted by combustion products which have lost heat to the boiler walls.

Few existing small industrial-size boilers are amenable to this NO_x reduction approach without significant modifications. Most industrial boilers have only one or two burners, and no capability to introduce additional combustion air through overfire or NO_x ports. Figure 2 shows the schamatic of a 40,000 lb/hr industrial watertube boiler as modified to allow staged air injection at various points in the furnace (Ref. 2). Figure 3 gives the results of the staging tests on natural gas for this unit. The data show that greater NO_x reductions occur as:

- the burner becomes more fuel-rich, and
- the separation from the burner of the staged air addition is increased.

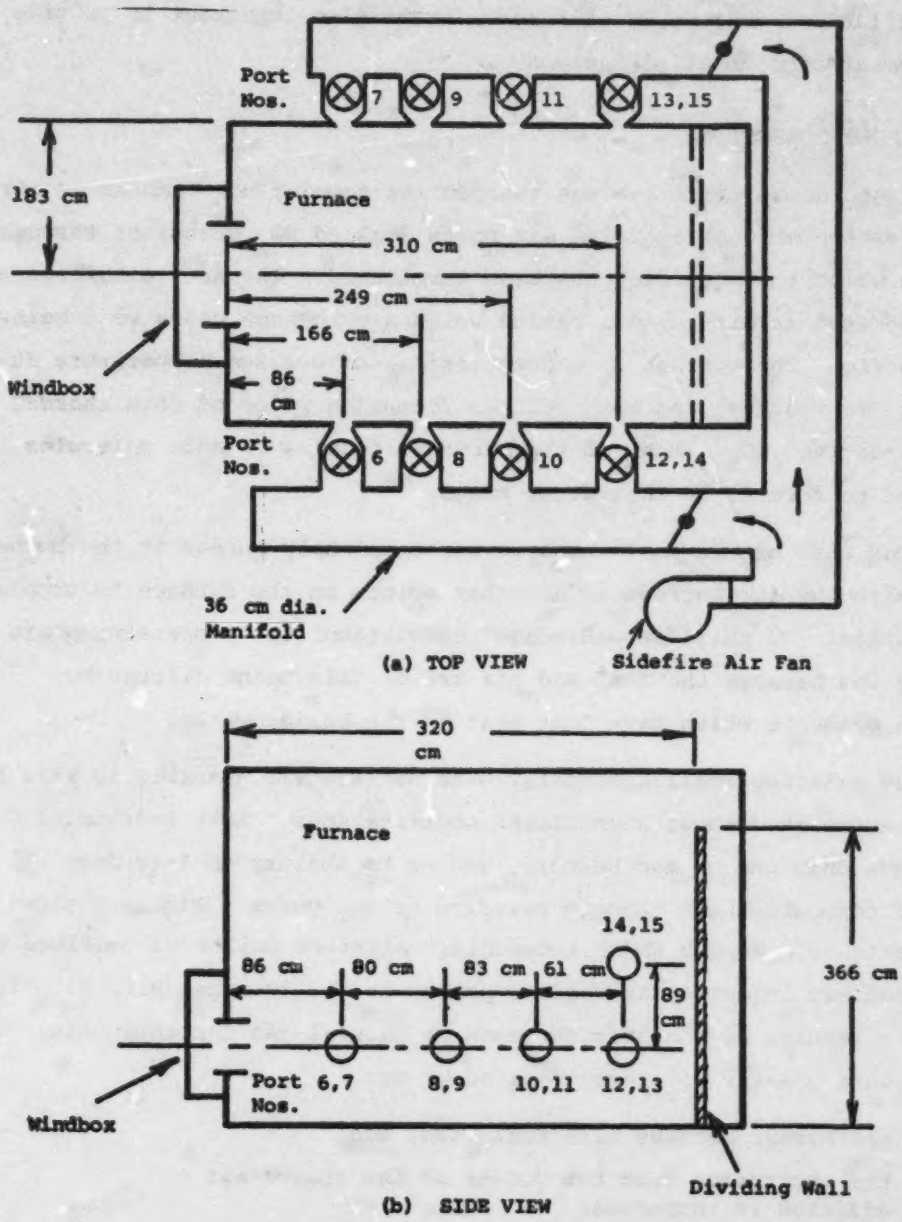

Figure 2. Schematic diagram of staged air system installed on a 40000 lb/hr watertube boiler.

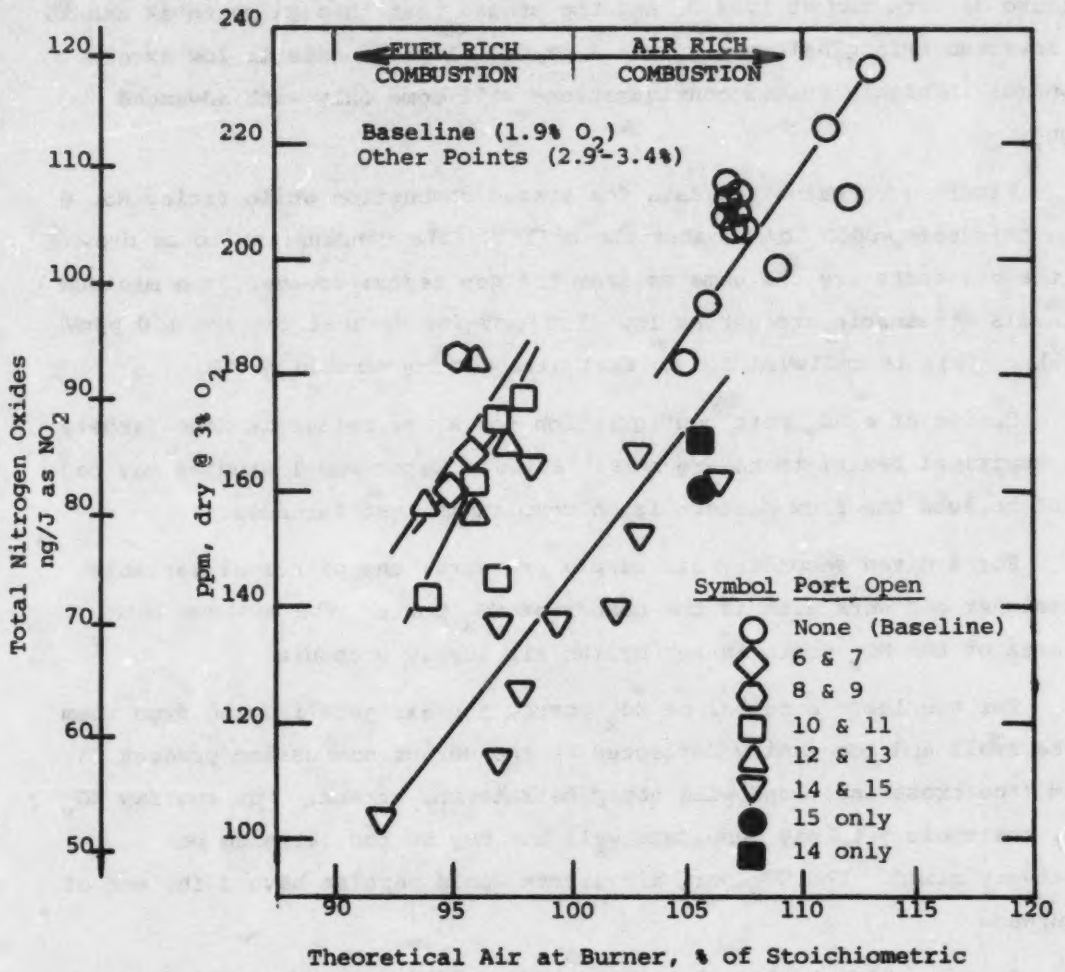

Figure 3. Reduction in total nitrogen oxides due to staged combustion air, natural gas fuel (40000 lb/hr, watertube boiler).

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At 95% theoretical air through the burner, the NO_x could be reduced from 160 ppm to 120 ppm by admitting the staged air through ports 14 and 15 rather than any ports closer to the burner. It was found that higher overall excess air had to be used in order to control combustible (CO) emissions at high degrees of staging. The baseline data (the open circles of Figure 3) were run at 1.9% O_2 and the staged test through ports 14 and 15 (the inverted triangles) were run at 3.4% O_2. Improvements in low excess O_2 control in highly staged configurations will come only with advanced designs.

Figure 4 contains the data for staged combustion while firing No. 6 oil on this same 40000 lb/hr watertube boiler. The conclusions to be drawn from the oil tests are the same as from the gas tests; however, the minimum NO_x levels attainable are not as low (100 ppmV for natural gas and 150 ppmV for oil). This is believed due to fuel nitrogen conversion to NO_x.

Design of a NO_x port configuration for a new boiler is done largely on an empirical basis; there are no set rules. Water-model studies may be helpful because the flow pattern is so complex in most furnaces.

For a given secondary air supply pressure, the principal variable the designer can work with is the number of NO_x ports. The minimum total flow area of the NO_x ports is set by the air supply pressure.

For too large a number of NO_x ports, the air jets issuing from them will be small and too easily deflected by the burner combustion product stream (the crosswind), and will not penetrate the stream. For too few NO_x ports, their air jets may penetrate well but may be too large to be effectively mixed. The NO_x port air stream would persist beyond the end of the furnace.

In general, delaying the mixing of second-stage air and first-stage combustion products allows the products to lose more heat and lowers NO_x. However, the flow pattern in the furnace may in some cases be such that moving the NO_x ports themselves downstream has little effect.

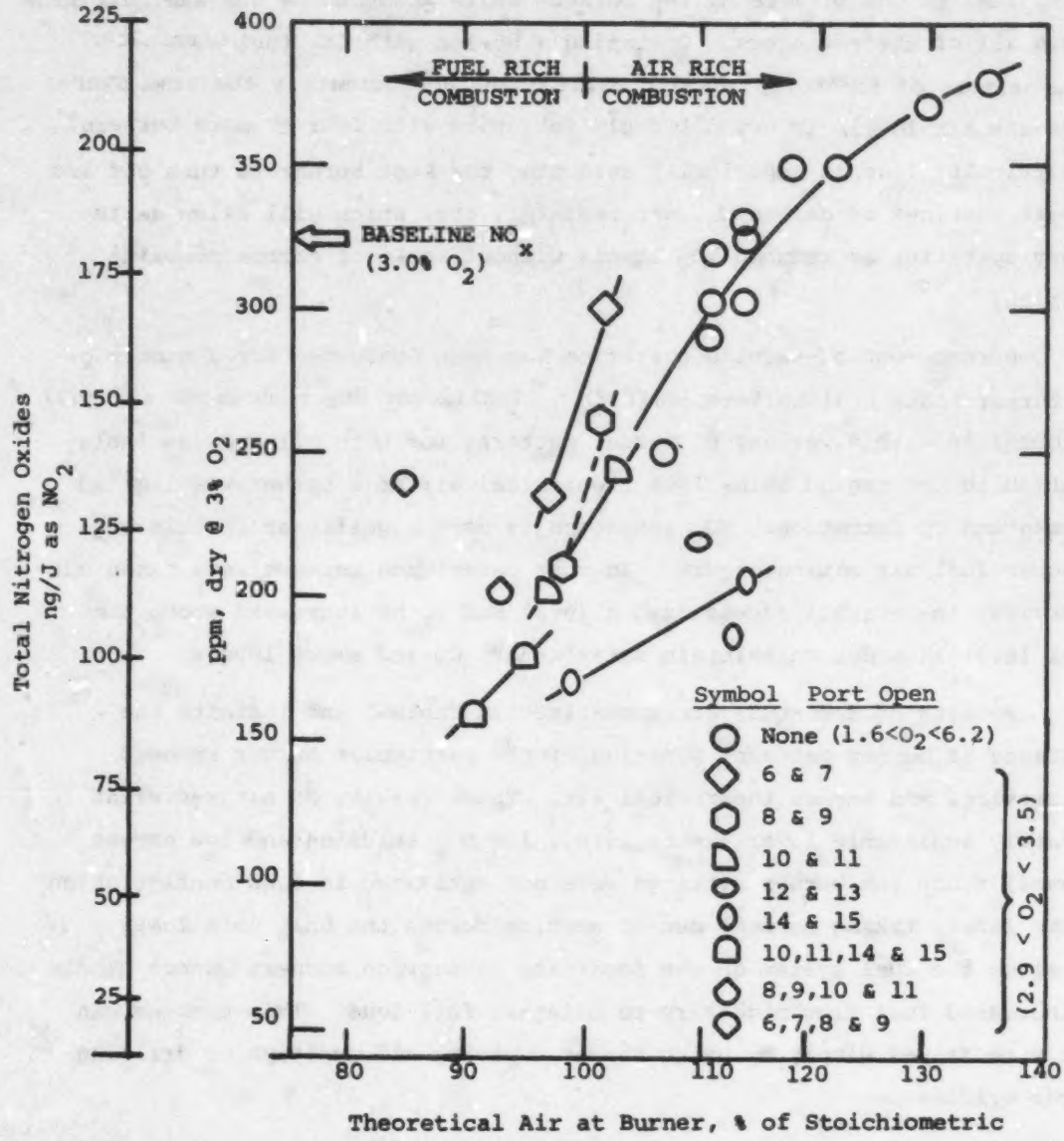

Figure 4. Reduction in total nitrogen oxides emissions due to staged combustion air, No. 6 oil fuel (40000 lb/hr watertube boiler).

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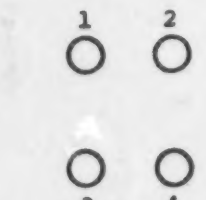
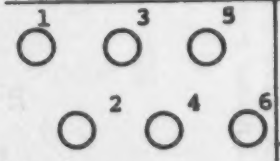
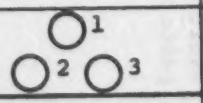
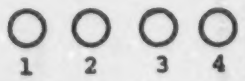
The downstream limit on NO_x port location is determined by emissions of smoke and combustibles. The temperature of the combustion product and air mixture must be above the ignition point.

In multiburner furnaces, staged combustion can be achieved by shutting off the fuel to one or more of the burners while maintaining the same air flow through all of the registers. Operating a boiler with the fuel terminated to one or more of the burners while maintaining approximately the same overall excess air level, is not difficult for units with four or more burners. The difficulty lies in empirically selecting the best burner to turn off and the best settings of excess O_2, air register, etc. which will allow satisfactory operation at reduced NO_x levels without smoke or carbon monoxide formation.

Burners-out-of-service operation has been evaluated for a number of multiburner industrial boilers (Ref. 2). Significant NO_x reductions (18-49%) were obtained with a variety of burner patterns for both oil and gas fuels. Operation in the region below 100% theoretical air at a burner was limited by smoke and CO formation. NO_x reduction is most significant in this region if proper fuel/air mixing occurs. In most cases when burners were taken out of service, the overall excess oxygen level had to be increased above the normal level in order to maintain satisfactory CO and smoke levels.

Results of the study are summarized in Table 1 and indicate the importance of burner pattern, position of the particular burner removed from service, and burner theoretical air. These results do not represent ultimately achievable lower limits (i.e., low NO_x emission and low excess O_2 level) since the burner settings were not optimized in each configuration. In some cases, taking burners out of service forces the unit to a lower load since the fuel system on the remaining in-service burners cannot handle the increased fuel flow necessary to maintain full load. This problem can usually be solved simply by using larger capacity oil gun tips or drilling out gas orifices.

TABLE 1. EFFECT OF TERMINATING FUEL FLOW TO SELECTED BURNERS

Burner Pattern	Fuel	Capacity 10^3 lb/hr	Test Load 10^3 lb/hr	Burner Out of Service	Excess Oxygen (%)	Burner Theoretical Air (%)	NO_x / NO_x, Normal O_2	Comments
	No.6 Oil	160	112	ABIS§	7.8	157	(281)*	Normal O_2
			118	2	8.3	123	0.6	
	No.6 Oil	105	80	ABIS	7.0	149	(289)	Normal O_2
			76	2	6.2	105	.83	
			76	1	6.55	108	.74	
	Nat. Gas	60	46	ABIS	2.6	114	(242)	Normal O_2
			41	2	2.6	82	.84	
	Nat. Gas	300	200	ABIS	2.7	114	(178)	Normal O_2
			204	1	3.8	91	.57	
	P.S.† 300	59	46	ABIS	2.9	117	(619)	Normal O_2
			43	1	6.1	118	1.05	
			47	3	5.5	113	.83	
			43	5	8.1	135	1.1	
	P.S. 300	65	50	ABIS	5.8	139	(466)	Normal O_2
			51	2	5.0	109	.98	
			52	4	5.0	109	.94	
	No.6 Oil	90	71	ABIS	7.4	115	(245)	Normal O_2
			60	1	8.2	109	.71	
	No.5 Oil	85	58	ABIS	7.3	152	(338)	Normal O_2
			51	1	8.1	122	.65	
			50	2	8.4	124	.72	
			50	3	8.4	124	.8	
			50	4	8.2	123	.85	

*Numbers in parentheses indicate NOx concentrations for normal operation.

†The API gravity of PS 300 oil is typical of No. 5 oil.

§"ABIS" means all burners in service

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Figure 5 presents data in which burners-out-of-service operation was investigated for natural gas and refinery gas on a horizontal, three-burner boiler (Ref. 2). The open square data points are for all three burners in service at two different excess air settings. The NO_x decreases with decreasing excess air. Further reductions are obtained when the fuel to the middle burner is terminated. During this off-stoichiometric firing, the overall flue gas excess O_2 concentration had to be increased from a low-excess-air configuration of 3.7% with all burners in service to 5.3% O_2 for the greatest degree of staging. This mode of staged combustion reduced the NO_x emissions by 30%.

The horizontal burner arrangement is not the most responsive to a burners-out-of-service modification. A four-burner boiler with a square burner pattern (two rows and two columns) was tested with pulverized coal (Ref. 2). A 40% reductior in nitrogen oxides emissions from 1011 to 618 ppmV was achieved by removing the top two coal burners from service while maintaining the same load (75% of design) and excess O_2, using the burner ports for second-stage air injection. The carbon monoxide emissions were essentially zero for all tests and boiler efficiency did not change from the baseline condition of 88%; however, smoke increased from a No. 2 to an unacceptable 6.5 Bacharach number when the top burners were out of service. In this configuration one must sacrifice NO_x reduction for smoke reduction. A trade-off between NO_x and smoke might, for example, be achieved at a 30% NO_x reduction and an acceptable smoke number.

In general, the results on industrial boilers showed:

- Burners-out-of-service operation is seldom more effective than just low-excess-air operation with all burners in service.
- Operating with burners out of service on a boiler with a square burner pattern (rows and columns) is more effective than with a staggered pattern. This is probably a result of better mixing between burners in the regular pattern than in the staggered arrangement.

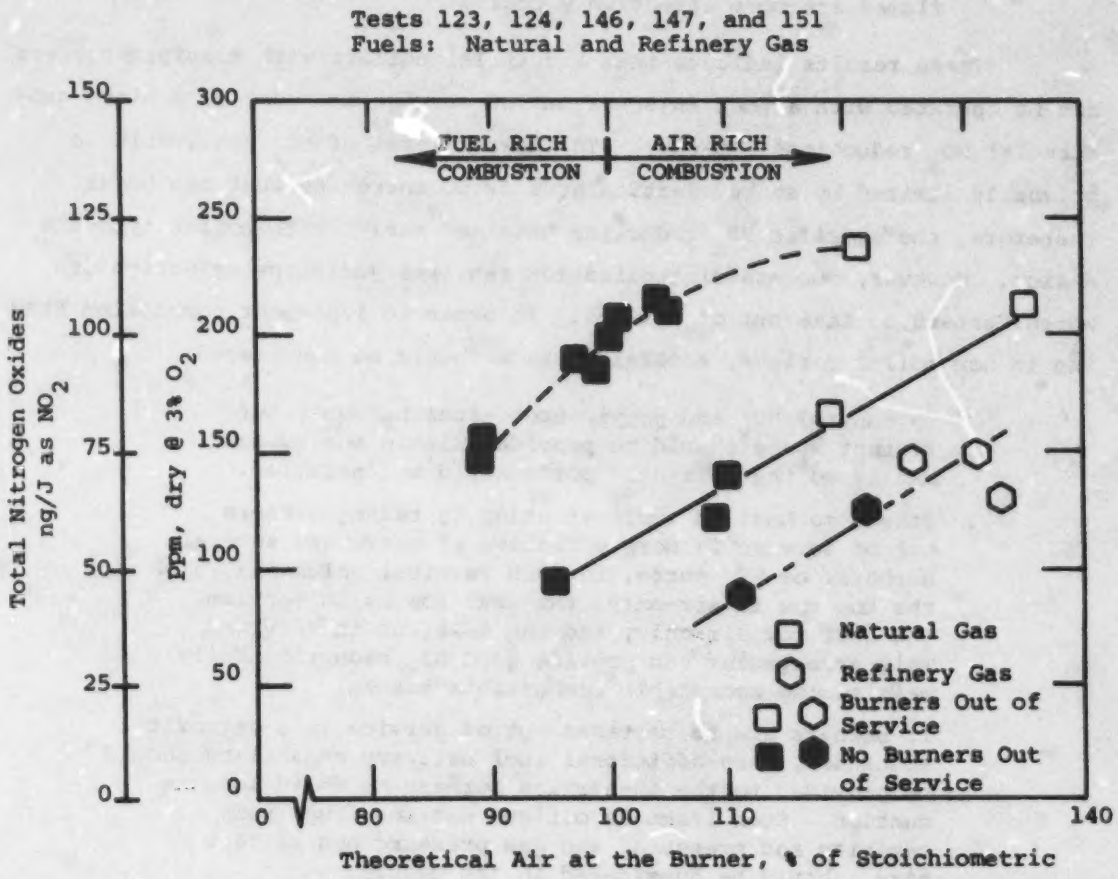

Figure 5. Reduction in total nitrogen oxides due to taking burners out of service, mixture of natural and refinery gas fuel.

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- Removing a burner from service which is close to the convective section is more effective than removing a burner from the row farthest from the convective section.

- Removing inner rather than outer burners is more effective; operation at lower excess oxygen levels is possible due to better mixing of the air from the burner out of service with the combustion products from the operating burners. Also, the outer flames are more effectively cooled.

These results indicate that industrial boilers with multiple burners can be operated with a fuel injector out of service in order to achieve substantial NO_x reductions (30-40%). The lowest level of NO_x achievable is primarily limited by smoke, particulates or CO increases that can occur. Therefore, the specific NO_x reduction obtained varies with boiler type and design. However, successful application requires judicious selection of which burners to take out of service. In order to implement combustion staging in new boiler designs, several factors should be considered:

- To control NO_x and provide good fuel burnout, sufficient space should be provided within the burner matrix so that air-only ports could be installed.
- Staged combustion implementation by taking burners out of service is more effective if there are several burners, or NO_x ports, in each vertical column in which the top row is air-only, the next row is in service, the next row air-only, and the next row in service. This arrangement can provide good NO_x reduction while maintaining acceptable combustible losses.
- If burners are to be taken out of service in a retrofit situation, then additional fuel delivery capability should be provided to the in-service burners to avoid load reduction. Such items as oil gun nozzles, fuel pump capacity and pressure, and gas pressure and orifice size, should be considered in the design.

3.4 BURNER ADJUSTMENTS

Adjustments to the burner fall into the category of modification of the fuel and air mixing patterns. These mixing patterns are modified to provide as much aerodynamically staged mixing as possible without having to provide additional air injection locations as discussed in the section on

staged combustion. The low-NO_x configuration that one hopes to achieve is a long, narrow flame where the fuel and air mix gradually over its entire length. Such flames can be achieved by reducing the swirl of the secondary air and by changing the angle at which the fuel is injected into the secondary air stream. For oil and pulverized coal, it may help to reduce the spray angle of the fuel injector. This technique has been found to be especially effective for fuels containing bound nitrogen (Ref. 14). However, these low-intensity flames alter the heat transfer characteristics of the boiler and may produce increased amounts of particulate emissions.

In the normal operating range of a burner with variable air swirl, decreasing the swirl usually decreases the NO_x. This is illustrated by Figure 6; in this case NO_x could be varied from 210 ppmV down to less than 140 ppmV at constant excess O_2 merely by changing air swirl.

At very high swirl settings the NO_x may again decrease if the flame changes to a widely flaring shape which is more effectively cooled by the walls and by entrainment of cooled combustion products from within the furnace.

With multiburner boilers, experience has shown the most important effect of air register adjustments to be in air flow rate to individual burners. This controls the air distribution and air/fuel mixture ratio across the burner front.

3.5 REDUCED COMBUSTION AIR PREHEAT

Reducing combustion air temperature reduces peak flame temperatures and to this extent lowers thermal NO_x formation. However, there is a direct trade-off with unit efficiency, which drops as preheat temperature is lowered.

Reduced air preheat temperature for NO_x control is most effective with natural gas. Gas-fired industrial boilers without air preheat typically have NO_x levels between 50 and 150 ppmV, while those with air preheat have NO_x levels between 90 and 400 ppmV.

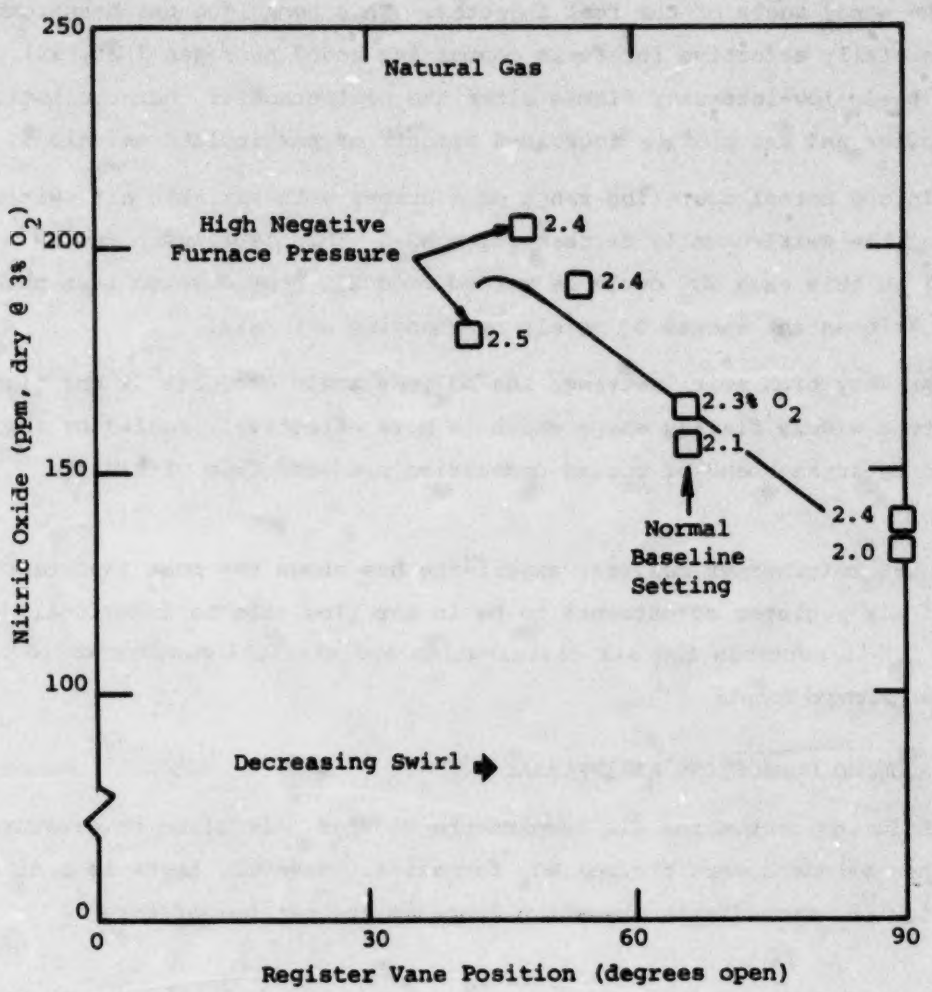

Figure 6. Effect of air register setting on NO_x for a specific boiler.

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The effect of preheated air was investigated in a 5 million Btu/hr lab scale combustor (Ref. 15). Data for three fuels and two excess air levels are shown in Figures 7 and 8. At normal excess air levels, (Figure 7), NO_x emissions with coal and oil exhibited little or no dependence on air preheat, but with natural gas NO_x emission was increased at higher air preheat. At high excess air levels, (Figure 8), the effect of preheat with natural gas remains about the same as for normal excess air. NO_x emissions with oil are slightly higher but the increment with increased preheat is unchanged. With coal fuel there is a significant increase in NO_x with increased air preheat.

Additional field test data have been obtained (Ref. 2) which support the above results. Figure 9 contains these data for three boilers firing oil and natural gas over a range of preheat temperatures.

3.6 FLUE GAS RECIRCULATION (FGR)

Applying flue gas recirculation requires that a fraction of the flue gas be withdrawn from the stack and ducted to the burners. During the combustion process, the recirculated flue gas acts primarily as a diluent, lowering the combustion temperatures. This reduction in bulk gas temperature suppresses the "thermal NO" formation. In addition, the presence of the recirculated flue gas reduces the oxygen concentration, which will tend to reduce the conversion of fuel bound nitrogen to NO_x.

There are two bases commonly used for expressing flue gas recirculation quantitatively. In the first, the mass flow rate, $\dot{m}$, of recirculated flue gas (FGR) is divided by the total flow of combustion products plus recirculated flue gas:

$$(\%\ \text{FGR})_1 = \frac{\dot{m}_{FGR}}{(\dot{m}_{CA} + \dot{m}_f) + \dot{m}_{FGR}} \times 100 \qquad (1)$$

where CA signifies combustion air and f signifies fuel. This formula gives the percent flue gas in the total oxidizing gas fed to the burners.

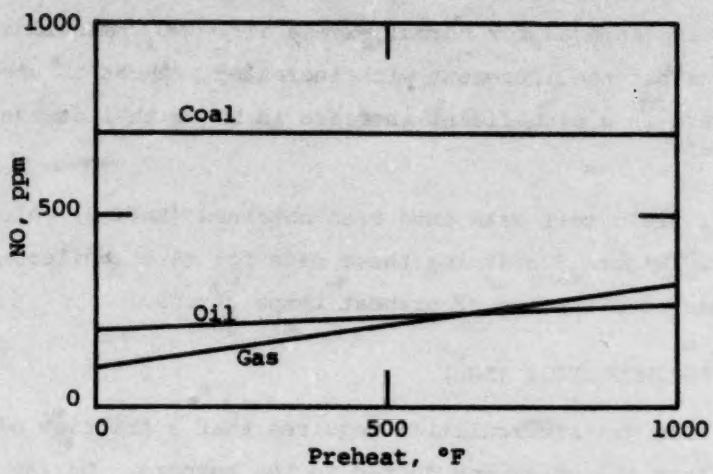

Figure 7. Effect of air preheat at normal excess air levels.

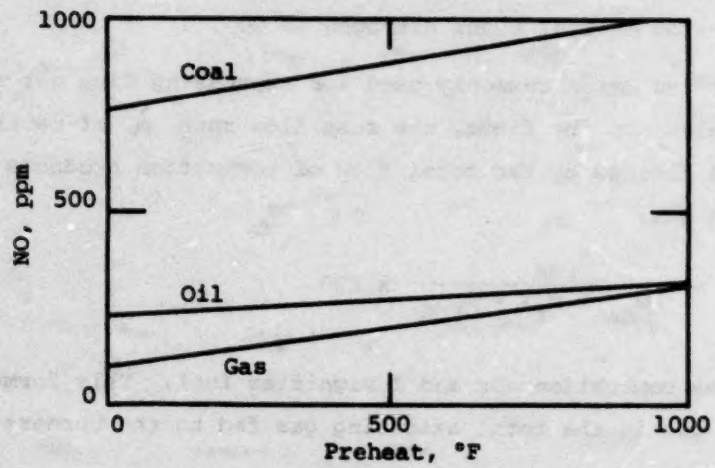

Figure 8. Effect of air preheat at high excess air.

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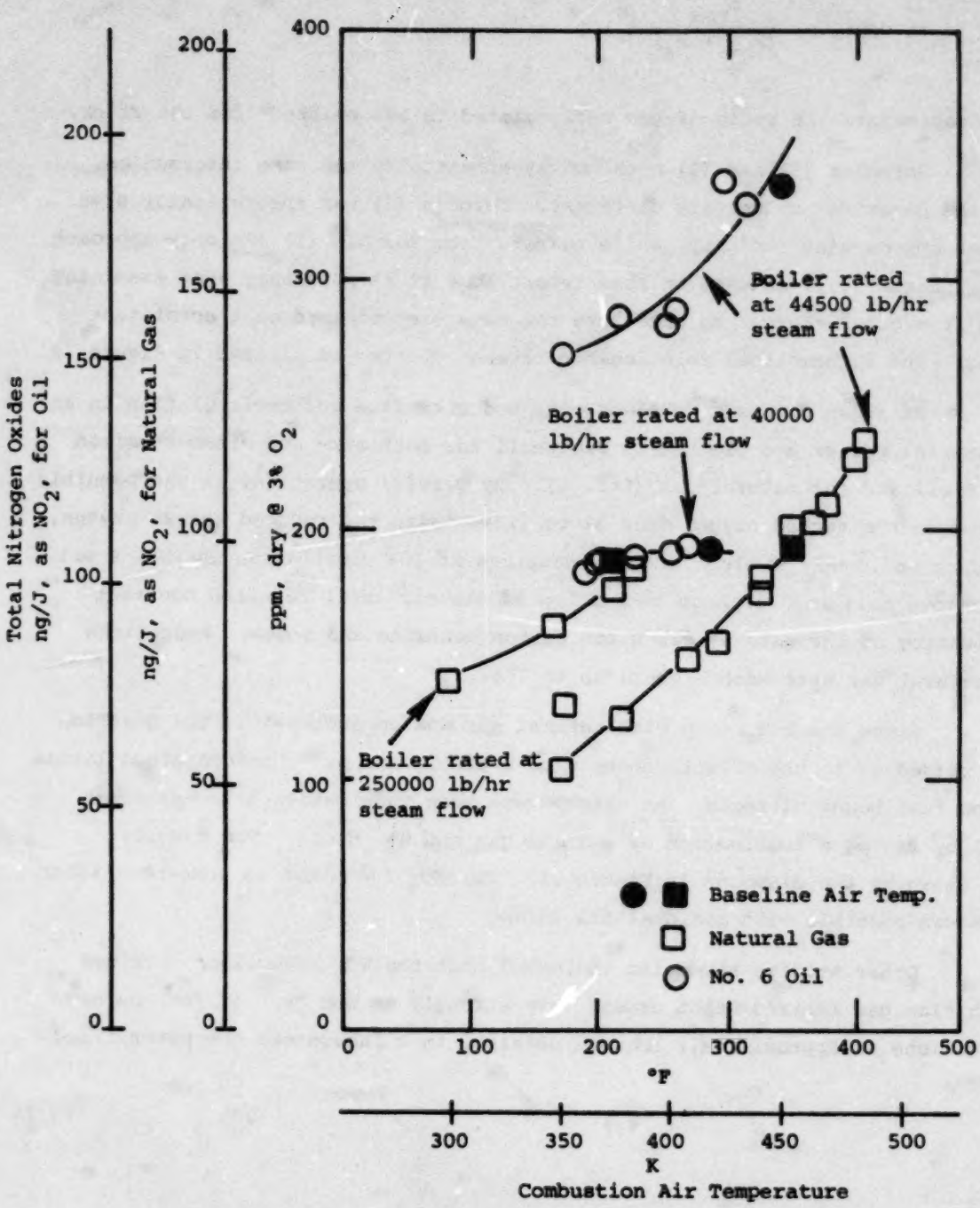
Total Nitrogen Oxides
ng/J, as NO_2, for Oil
ng/J, as NO_2, for Natural Gas
ppm, dry @ 3% O_2
Boiler rated at 44500 lb/hr steam flow
Boiler rated at 40000 lb/hr steam flow
Boiler rated at 250000 lb/hr steam flow
Baseline Air Temp.
Natural Gas
No. 6 Oil
°F
K
Combustion Air Temperature

Figure 9. Effect of combustion air temperature on total nitrogen oxides emissions with gas and oil fuels for three watertube boilers.

In the second method the amount of recirculated flue gas is divided only by the mass of flue gas leaving the stack:

$$(\%\ FGR)_2 = \frac{\dot{m}_{FGR}}{(\dot{m}_{CA} + \dot{m}_f)} \times 100 \qquad (2)$$

This represents the ratio of gas recirculated to gas emitted from the stack.

Formulas (1) and (2) both convey essentially the same information, but the numerical values are different. Formula (2) can theoretically give values approaching infinity, while numbers from formula (1) can only approach 100%. Formula (1) is used in this report, but it is necessary when examining data from other sources to make sure the data are compared on a consistent basis. The mathematical relationship between the two is plotted in Figure 10.

Nitrogen oxides reductions obtained with flue gas recirculation in an industrial boiler are plotted in Figure 11 for both air- and steam-atomized No. 6 oil and for natural gas (Ref. 2). By careful operation, it was possible to reduce the excess oxygen from 3% to 1.3%. With the reduced excess oxygen, a reduction in NO_x of about 20% was realized at 20% circulation for No. 6 oil. To achieve this reduction at such a low excess air level required constant monitoring of the exhaust gases for carbon monoxide and smoke. Reductions on natural gas were much higher, up to 70%.

Since the reduction with natural gas was so successful, the question was raised as to the effectiveness with a distillate oil that contained little or no fuel bound nitrogen. An attempt was made to simulate a low-nitrogen fuel by firing a combination of natural gas and No. 6 oil. The results are shown by the diamonds in Figure 11. The NO_x reduction is somewhat higher than was possible with residual oil alone.

Other studies have also indicated that the NO_x reductions obtained with flue gas recirculation depend very strongly on the type of fuel burned. Reductions of approximately 22% were obtained in a laboratory combustor fired

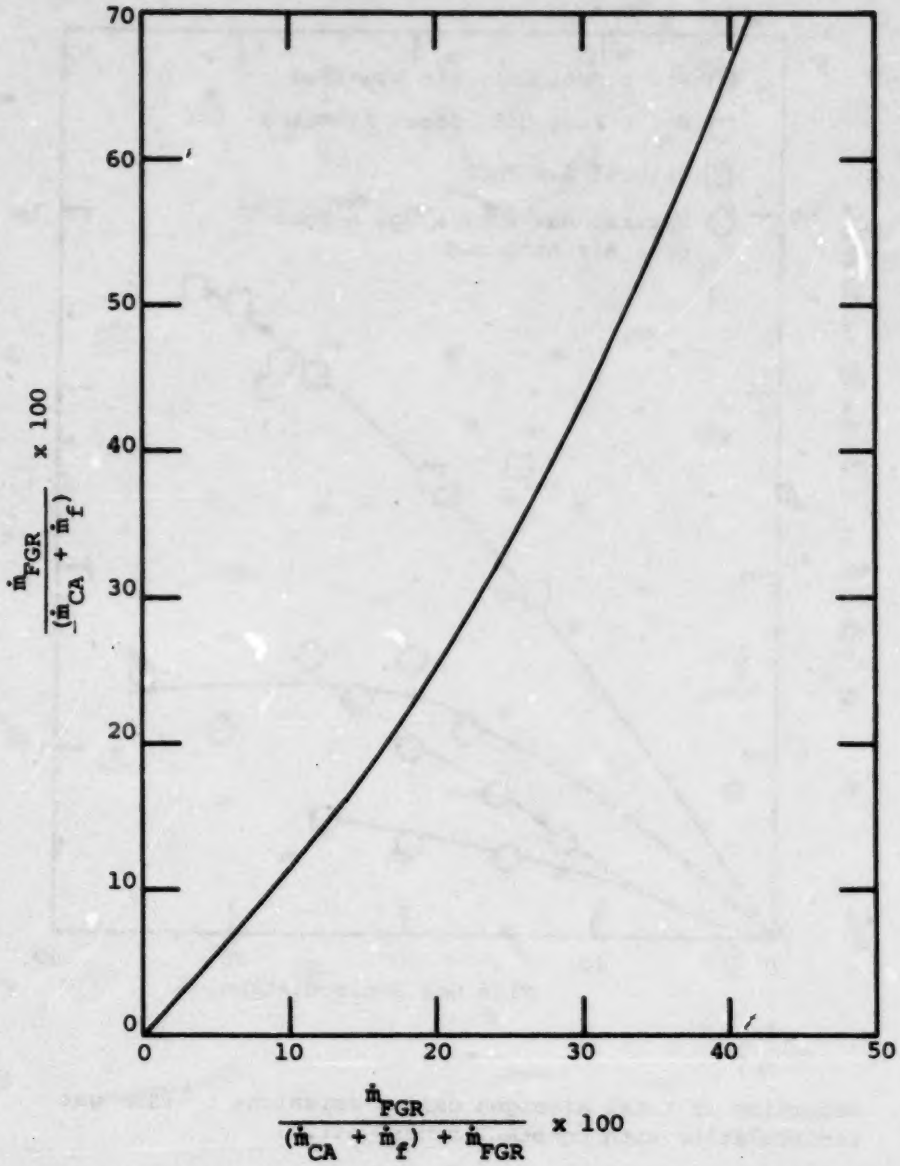

Figure 10. Relationship between two definitions of "percent flue gas recirculation."

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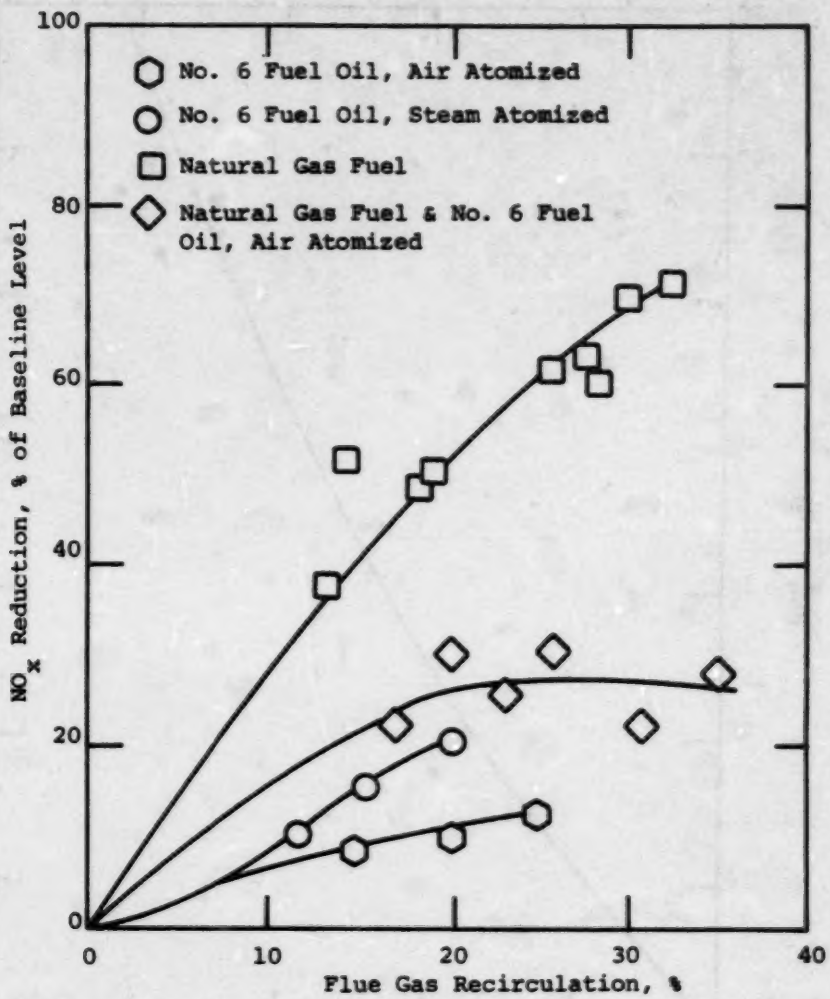

Figure 11. Reduction in total nitrogen oxides emissions by flue gas recirculation with constant excess air.

6001-49

with a distillate oil doped with 1% pyridine, while 85% reductions were realized with the distillate fuel alone (Ref. 16). A reduction of 33% was obtained in a 50 hp Cleaver Brooks boiler fired with a residual fuel oil (Ref. 7). Reductions of 25%, 38%, and 68% when firing residual No. 6 oil, distillate No. 2 oil, and natural gas, respectively (30% flue gas recirculation) have been observed (Ref. 9). The differences were attributed to (1) the different combustion characteristics of the fuels, and (2) the bound nitrogen content (natural gas - 0%, No. 2 oil - 0.05%, No. 6 oil - 0.35% by weight).

Figure 12 shows results obtained for flue gas recirculation into the secondary combustion air for coal, oil and natural gas (Ref. 15). The greatest reductions were achieved on natural gas, with coal and oil following in that order. These data indicated that FGR was not very effective for NO_x reduction on coal or oil.

It was also observed that FGR is not a very effective NO_x reduction technique on large pulverized-coal-fired boilers (Ref. 11). Figure 13 shows NO data for FGR with all burners in service at two different loads and for staged firing at two loads. The gas recirculation reduced NO_x emissions by 16% with all burners in service but had only a small effect when combined with staged combustion.

Data from a natural-gas-fired utility boiler, Figure 14, shows the effect of gas recirculation on a 320 MW tangentially fired boiler. At 30% recirculation, NO_x emissions dropped below 100 ppm from a baseline of 270 ppm, for a reduction of 66%.

The method or location of injecting the flue gas has also been found to be very important. There are several methods for adding flue gas to the burner. It can be mixed with the combustion air, or a separate passage can be provided.

Flue gas recirculation at three different locations was evaluated in an industrial burner firing into a 39" diameter tunnel: total air, secondary air, and injectors located at the exit of the burner throat (Ref. 17).

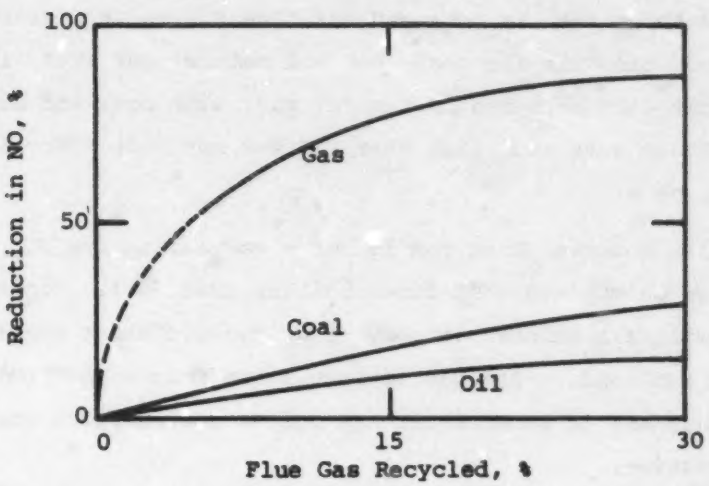

Figure 12. Secondary flue gas recirculation.

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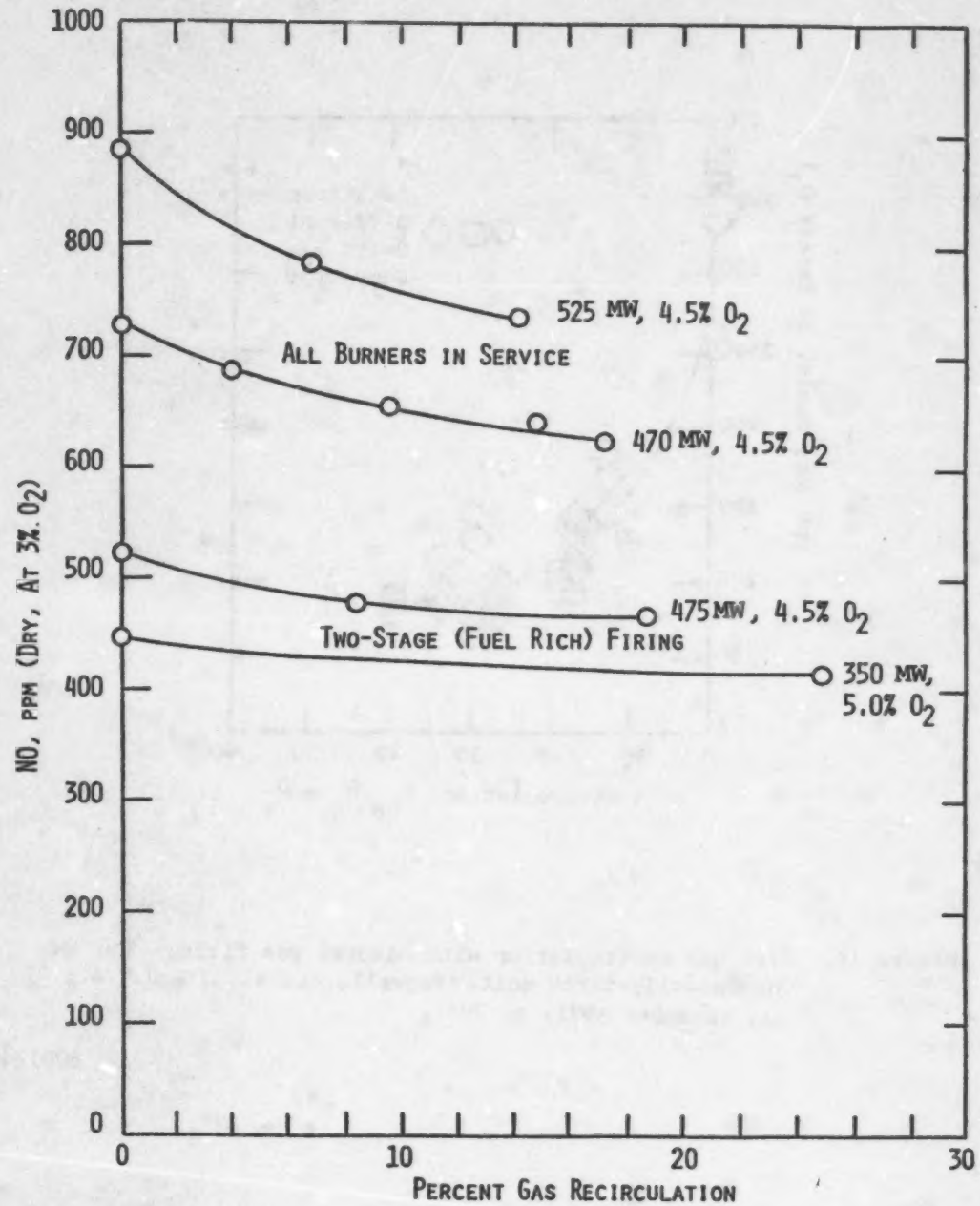

Figure 13. NO dependence on gas recirculation for normal (air-rich) and two-stage combustion of pulverized coal.

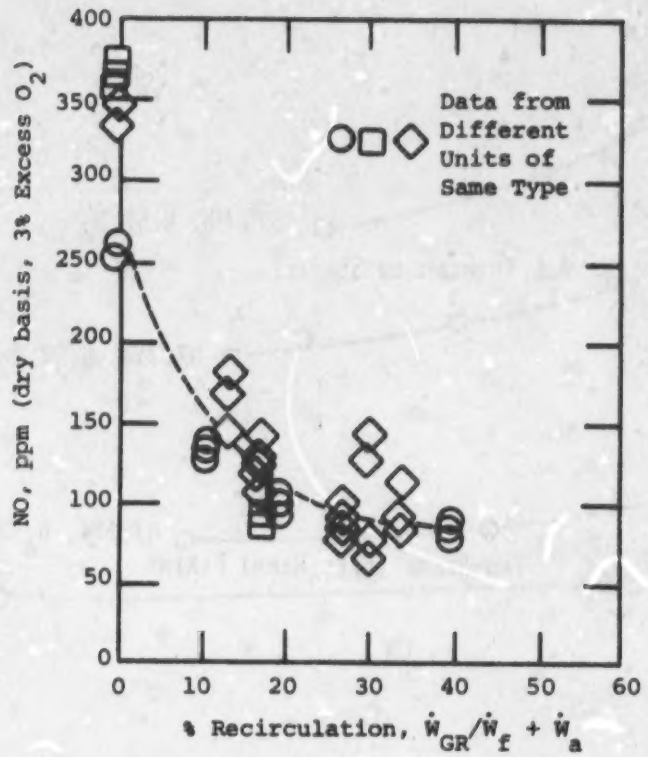

Figure 14. Flue gas recirculation with natural gas firing; 320 MW tangentially-fired unit. (Bagwell, et. al, J.A.P.C.A., 21 11, November 1971, p. 704).

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Typically, 50% reductions were obtained when the flue gas was added to the primary or secondary air. When the flue gas was added through the injectors at the exit of the throat, no reductions in NO_x were obtained.

In a 90 hp firetube facility (Ref. 9) flue gas could be added to the primary air, secondary air, total air, throat injectors, or through the natural gas ring when firing oil fuel. These results showed:

1. No NO_x reductions obtained when the flue gas was added through the throat injectors or secondary air stream.

2. Adding the flue gas to the total air stream or primary air stream was effective in reducing NO_x emissions.

3. Adding the flue gas to the total air stream is probably the most effective overall. When large quantities of flue gas were added through the primary, the NO_x emissions tended to rise. This was probably due to the increased mass flow through the primary air passage with associated increased fuel air mixing rates.

4. NO_x reductions were obtained with only small increases in smoke emissions, typically one Bacharach number.

In a recent study, discussed more fully in Section 5, flue gas was added to the combustion air just a few inches upstream of the throat. For natural gas, it was necessary to use high air swirl and a central gas gun rather than a ring in order to stabilize the flame.

The results are shown in Figures 15 for natural gas, 16 for No. 2 oil of negligible nitrogen content, 17 for No. 6 oil (0.20% N). Substantial reductions in NO_x were achieved with gas and No. 2 oil at 3% excess O_2, and a significant reduction was achieved with No. 6 oil when excess oxygen was minimized while using FGR.

In considering the use of FGR for NO_x control on new industrial boilers, several factors should be evaluated. In light of the preceding discussion, the type of fuel to be used should be of paramount concern: for some boilers FGR is only effective with natural gas fuel. Therefore,

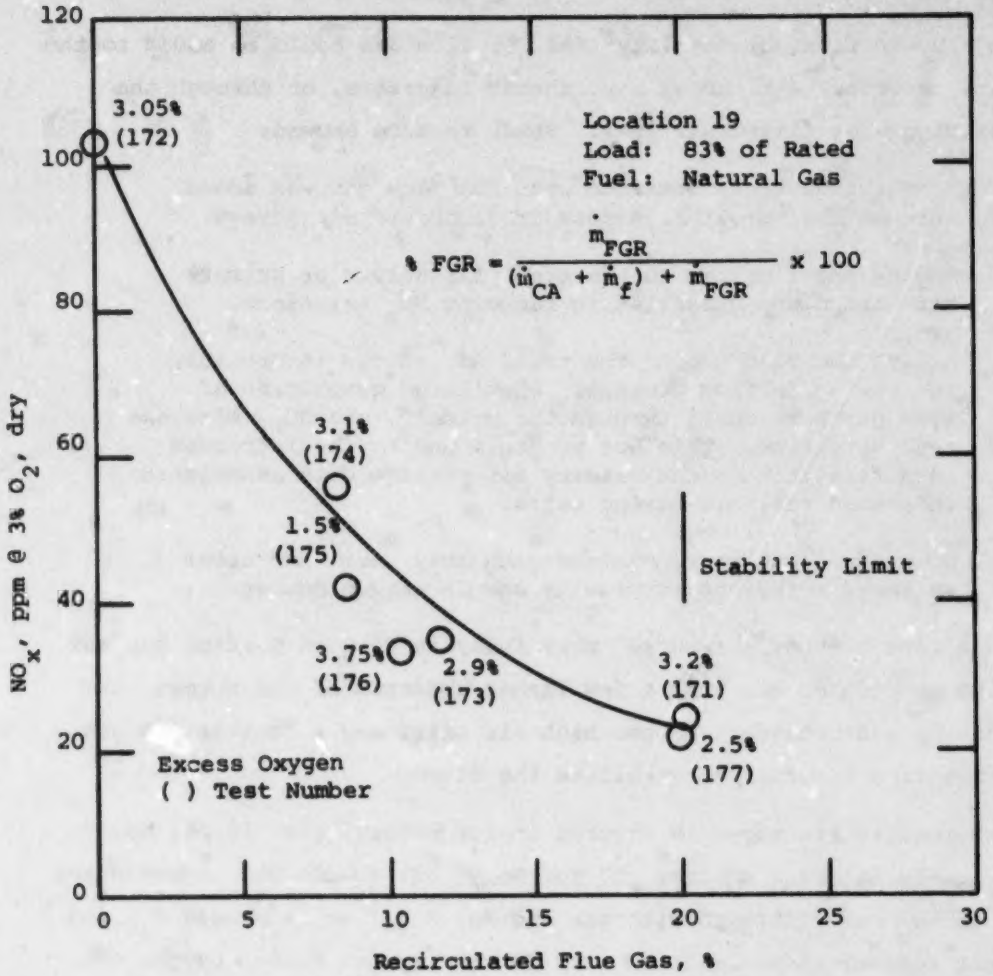

Figure 15. The effect of flue gas recirculation rate on NO_x emissions (natural gas).

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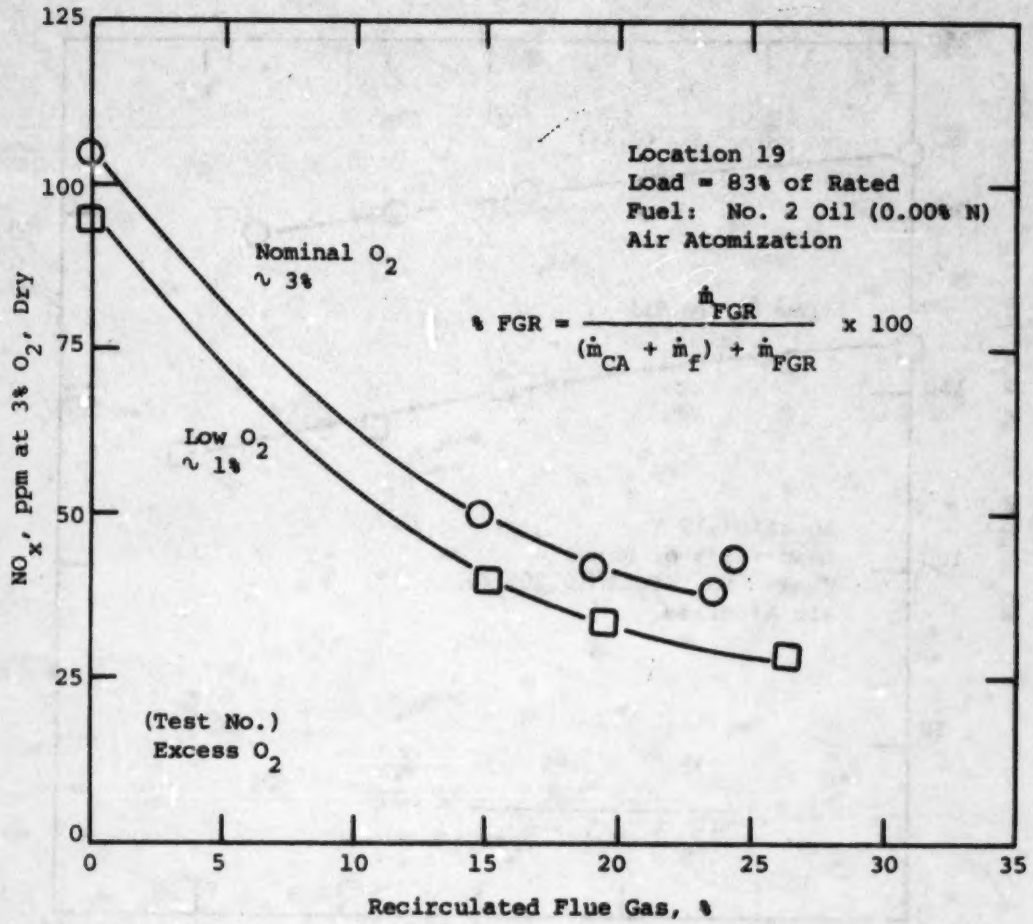

Figure 16. NO_x emissions as a function of percent flue gas recirculation (No. 2 oil).

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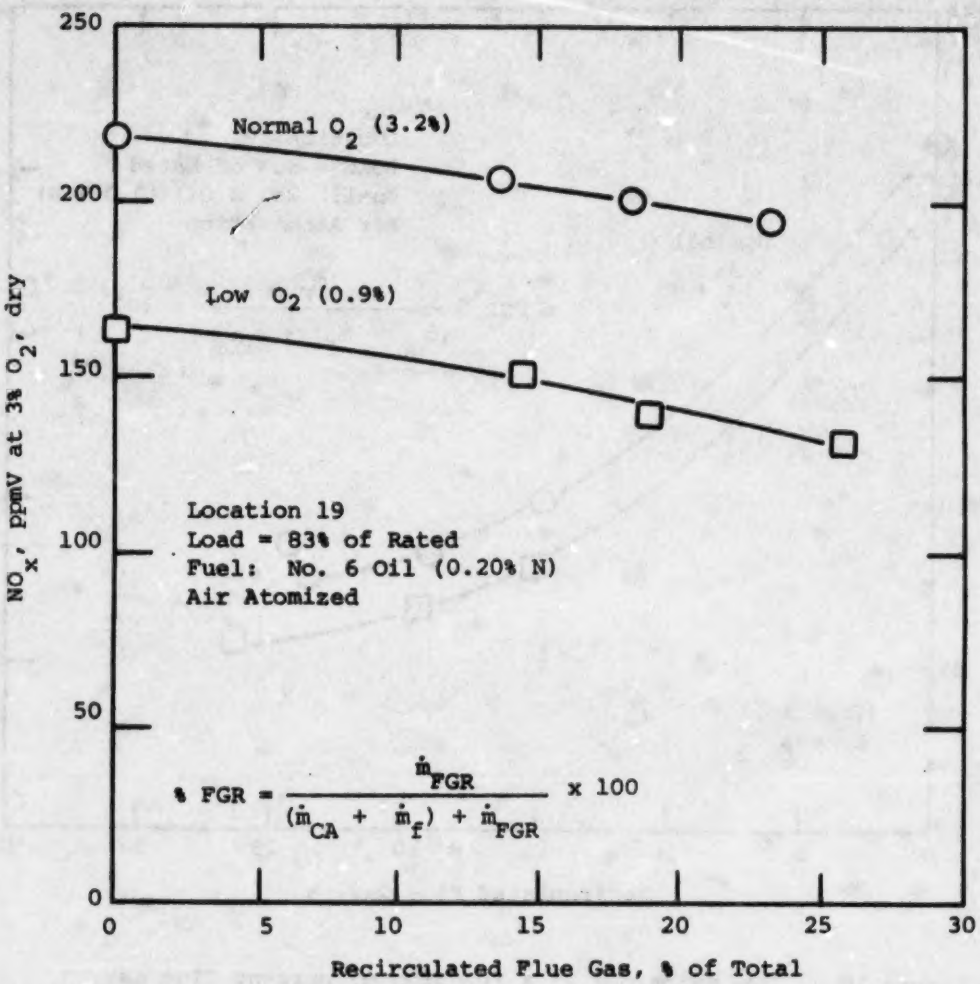

Figure 17. The effect of flue gas recirculation on NO_x emissions (No. 6 oil).

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if gas is in limited supply as an industrial boiler fuel, FGR may not be a useful control technique. The cost per unit of NO_x reduction for FGR versus other NO_x reduction techniques should be weighed before selecting a NO_x control combustion modification. Some factors that make up the cost-to-reduction quotient are:

- impact on overall energy efficiency (auxiliary loads)
- system maintenance
- flame stability (safety)
- amount and method of injection

No overall recommendations can be set for FGR application to industrial boilers due to the large number of designs covered by the category. Individual cost estimates must be made according to unit size and type.

3.7 WATER INJECTION

Water injection into preheated combustion air can be thought of as a simpler alternative to flue gas recirculation. To be effective in reducing NO_x, the water must be evaporated before passing through the flame. Water injection involves high stack gas heat loss and is not very effective on fuel-N-derived NO_x. The method has been used on boilers, but normally is considered unacceptable because of the associated efficiency loss.

3.8 FURNACE CHARACTERISTICS

As the rate of heat release of a particular furnace increases, the NO_x emissions increase only slightly for gas and oil; however, the increase is rather more marked for coal. The coal flame radiates less effectively to the walls due to its large optical density; this lowers the heat removal from the core of the flame whence the liberated heat goes to increase the average temperature of the flame and also the NO_x emissions.

Figure 18 presents data on NO_x emissions as a function furnace load for gas and coal fuels (Ref. 15).

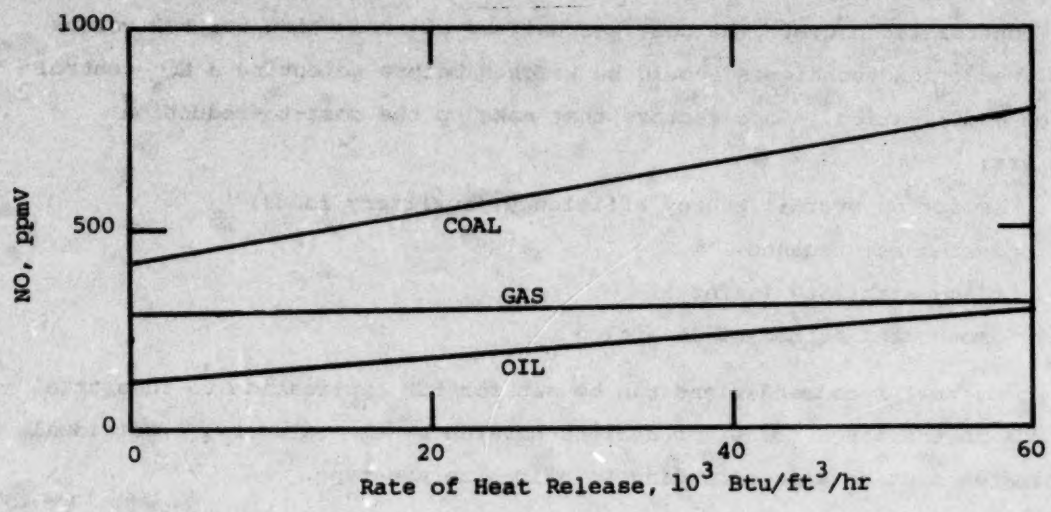

Figure 18. Effect of heat release rate on NO emissions.

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Liberal furnace volume makes it easier to use certain NO_x reduction techniques which involve distributing the combustion throughout a larger volume. These include low-excess-air firing and staged combustion. However, large furnaces in general can cool the flame more effectively. For this reason, another useful parameter is the furnace heat-absorbing area.

For gas-fired industrial boilers it was found that by using the furnace heat absorbing area as the basic parameter and then correcting for the furnace excess air level, a reasonable correlation of NO_x data could be achieved (Ref.20). The test data for watertube boilers for which the necessary furnace information was available are shown in Figure 19. The band shown includes load variations, air preheat effects, different burner ring designs, and air swirl effects. The very low NO_x values measured for test 67 are seen to be largely due to the high furnace heat-absorbing area for the amount of heat released.

Since these data were taken from boilers having various types of wall construction, it was necessary to estimate the actual heat-absorbing surface area using the available information. It was assumed for boilers with construction of water tubes separated by refractory that only half of the area on the furnace sidewalls, ceiling, and the end wall opposite the burner was effective heat absorbing area. The furnace floor and burner wall (as well as the refractory between the tubes) were assumed to be ineffective as heat-absorbing areas. The boilers with either tangent-tube or flanged-tube construction were assumed to have wall and ceiling areas, as described above, 100% effective as heat-absorbing surfaces; the burner wall and the floor were assumed to be ineffective.

The data for firetube boilers do not fall into agreement with data for the watertube boilers, but appear to form another band of data with a much shallower slope than for the watertube boilers; this is shown in Figure 20. The lower levels of NO_x are due in part to the lack of air preheat on all the firetube units and may be partly due to the differences in the heat-transfer characteristics of the furnace.

Data for much larger (utility) boilers are compared to the industrial boiler data in Figure 21. A significant aspect of the utility boiler data is the spread seen in the NO values around the band of the industrial boiler data. A possible explanation of this spread is the influence of the gas ring orifice design. Boiler No. 6 has a large number of small gas orifices, while boilers No. 4 and No. 5 have approximately half the number of gas orifices of boiler No. 6, but of a larger orifice diameter. The remaining boilers shown have rings varying in number and size of gas orifices between those of No. 4, No. 5, and No. 6.

Heat release per unit heat-absorbing area can of course be lowered by reducing the firing rate. Emissions of NO_x almost always decrease as boiler load is lowered.

The reduction of total steam load to control NO_x emissions would not be an acceptable control strategy in any but the most drastic of circumstances. However, the change in NO_x emissions with unit firing rate might be utilized

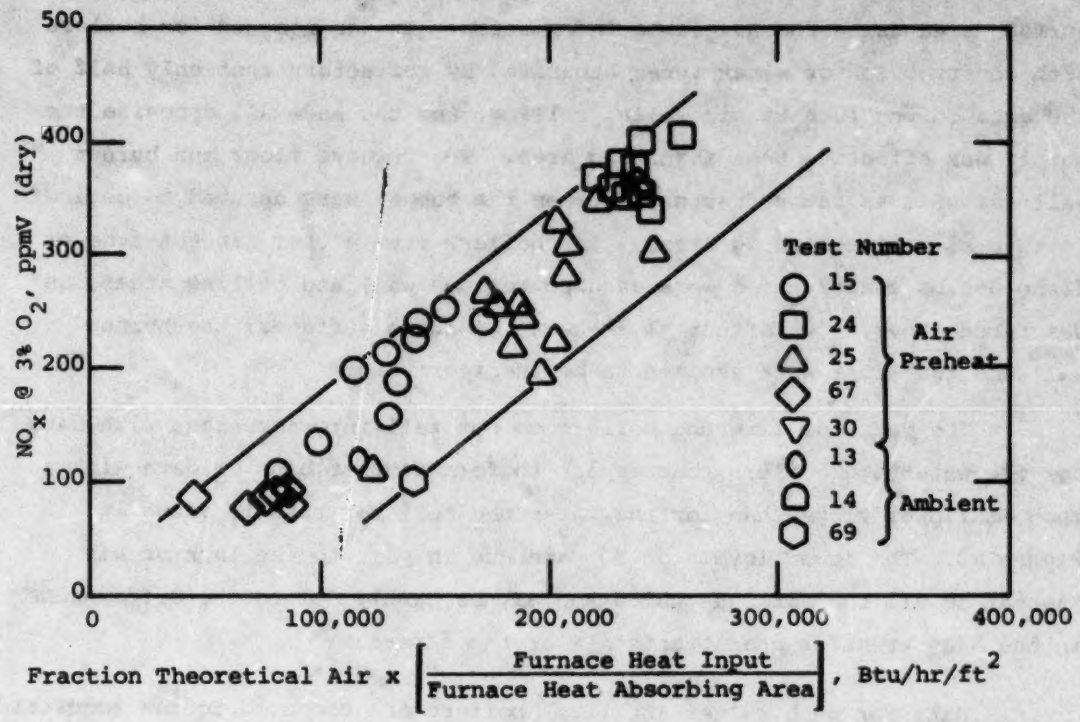

Figure 19. EPA ring burner test results for watertube boilers.

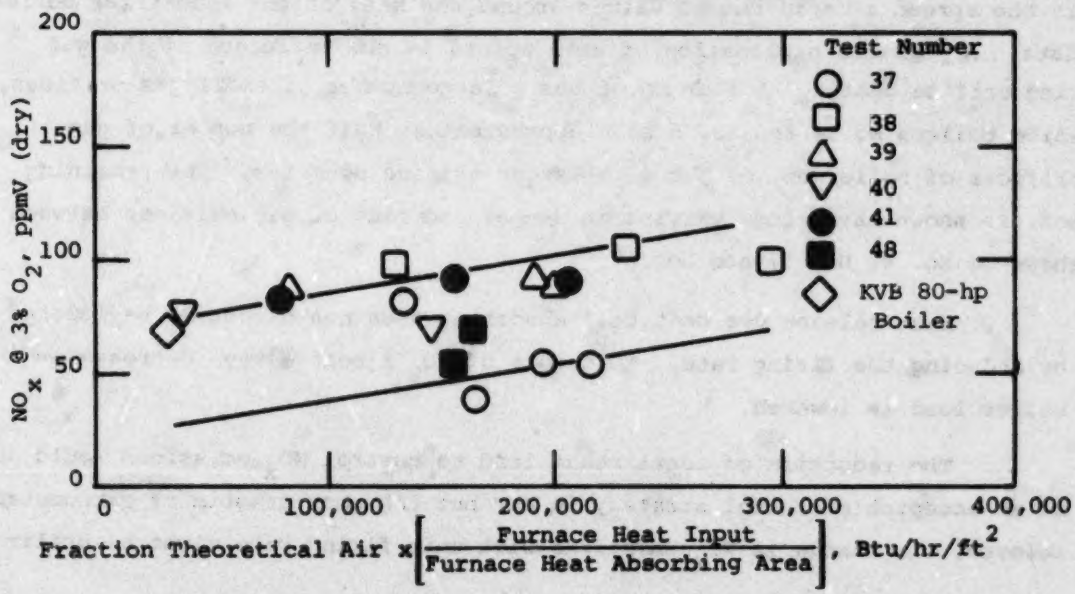

Figure 20. EPA ring burner test results. Firetube boilers, ambient-temperature air.

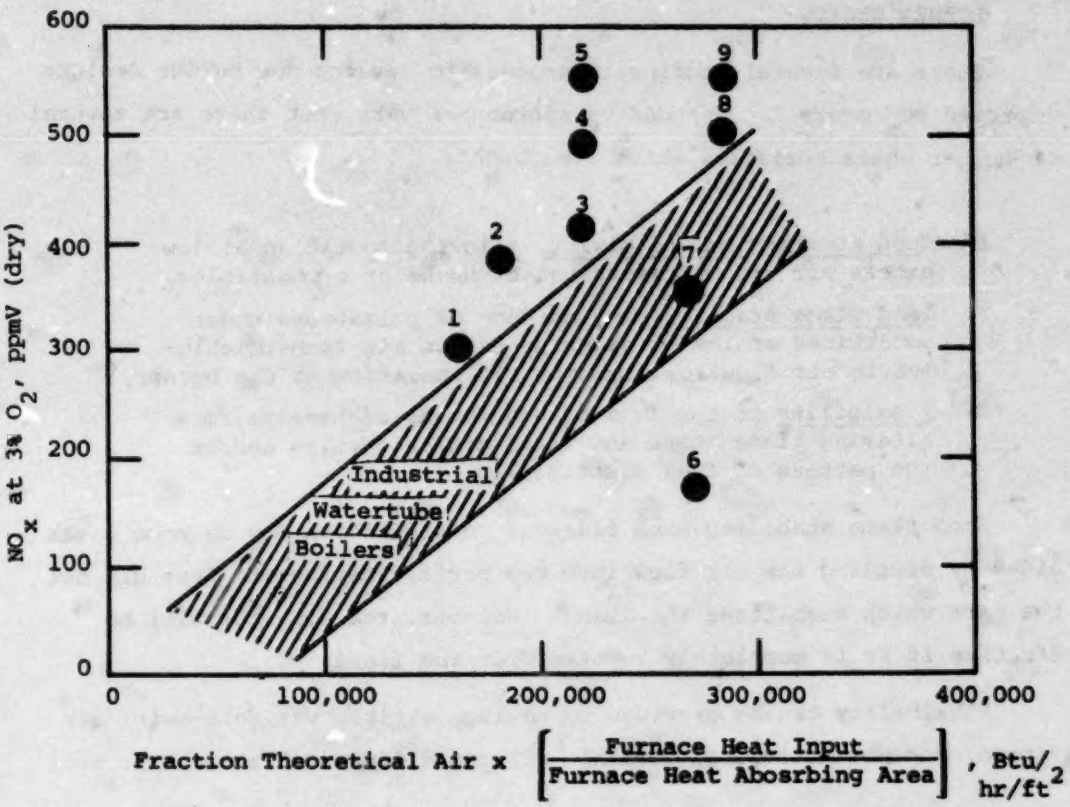

Figure 21. Comparison of EPA industrial boiler ring burner test results to utility boiler ring burner test results.

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in a plant containing sufficient excess capacity such that the required steam load could be produced using all boilers at partial load, as opposed to using fewer boilers at full load. A minimum-NO_x firing strategy might then be possible without limiting steam production.

Field tests of both firetube and watertube industrial boilers indicate that there is no significant difference in emissions between the two types of units when firing the same type of fuel without air preheat (Refs. 2, 4).

3.9 BURNER DESIGN

There are several studies in process to develop new burner designs for improved NO_x control. The design approaches vary, but there are several common burner characteristics which are sought:

1. Good atomization and mixing, allowing operation at low excess air without emissions of smoke or combustibles,
2. Good flame stability and absence of pulsations under conditions of low or negative excess air (substoichiometric air flow) or flue gas recirculation at the burner,
3. Flexibility in the form of adjustment mechanisms for altering flame shape and local air velocities and/or the pattern of fuel distribution.

Good flame stability with flue gas recirculation may in some cases be aided by dividing the air flow into two parts, keeping the flue gas out of the part which stabilizes the flame. However, the flue gas will be ineffective if it is completely removed from the flame.

Flexibility can be provided by having multiple variable-swirl air registers, movable diffusers, variable oil gun-diffuser relationship, etc.

If a furnace is so long and narrow that flame impingement on the wall is not a problem, a narrow oil spray atomizer (perhaps 30°) could help to lengthen the flame and thus reduce the NO_x.

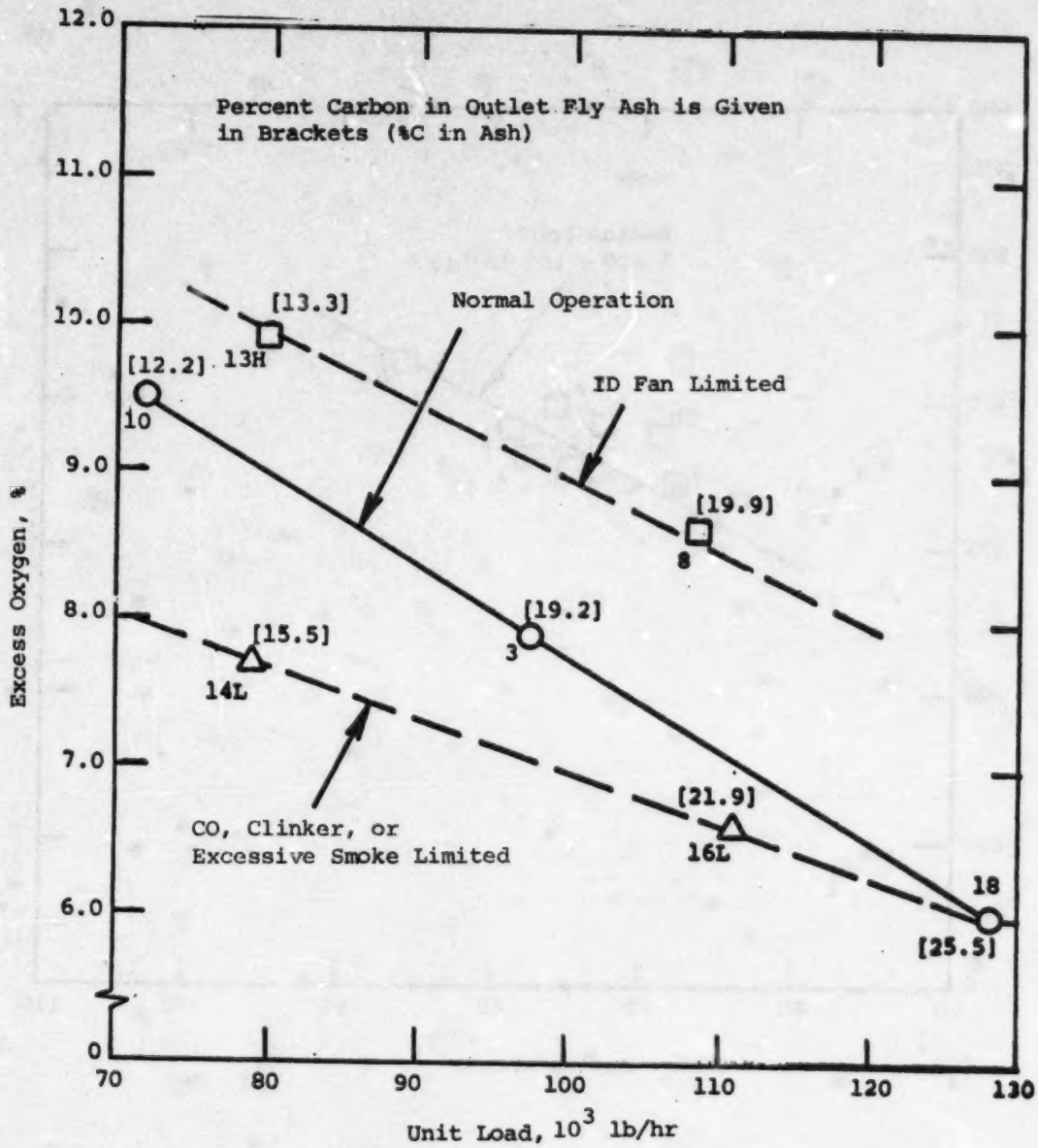

Figure 22. Operating limits of a spreader stoker burning a western subbituminous coal.

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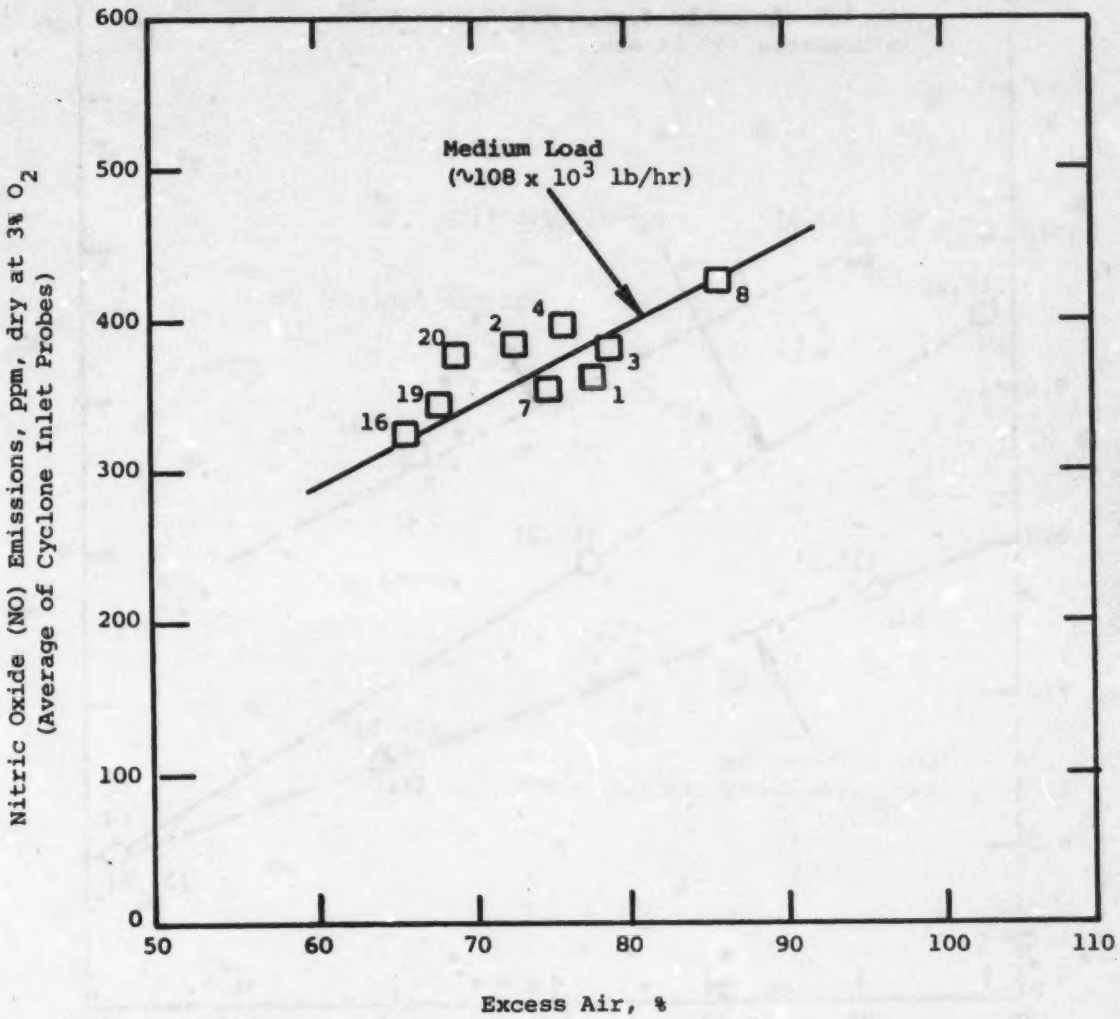


Figure 23. NO_x emissions from a spreader stoker burning a western subbituminous coal (coal fuel N = 0.68%).

3.10 COAL FIRING

There are two methods used to fire coal in industrial boilers: suspension firing of pulverized coal, and stoker firing of lump coal. Due to the nature of the combustion in each of these firing types, the NO_x emissions are radically different. The high intensity of the pulverized firing, if not properly controlled, can lead to much higher NO_x emissions than from the low-intensity stoker combustion.

In a stoker the fuel, for the most part, devolatilizes under fuel-rich conditions in a bed. The volatiles mix with air and burn above the grate. After the volatiles are gone, the remaining carbon burns in a diffusion flame around the coal particle. This mode of combustion represents a naturally staged configuration. Figure 22 is a plot of excess O_2 as a function of unit load and shows the limits of staging that were achieved with a particular spreader stoker of 160,000 lb steam/hr capacity. The lower dashed line represents the limit defined by excessive combustible losses and/or fuel bed clinker formation. The upper dashed line is the limit of the induced draft fan capacity. Normal operation lies between these two dashed lines and is defined, in this case for a western coal, by the solid line. The lower the excess air requirements at any load the lower will be the NO_x emisisons, as shown in Figure 23 for the same fuel and unit.

An illustrative example of the effect of stoker firing type on NO_x emissions can be made by comparing the data in Figure 24 with the data in Figure 23. The data in Figure 23 are for a spreader stoker, in which about half of the combustion takes place in suspension because the coal is fed to the furnace by a rotating paddle wheel. Combustion is completed after the coal particles fall onto a grate. On this unit, NO_x emissions were in the 300-400 ppm range, depending on excess O_2. Figure 24, on the other hand, contains NO_x data (for two coals) gathered on a watercooled vibrating grate stoker where more than 90% of the combustion takes place in the fuel bed. NO_x emissions on this unit were in the 150-250 ppm range, depending on excess air.

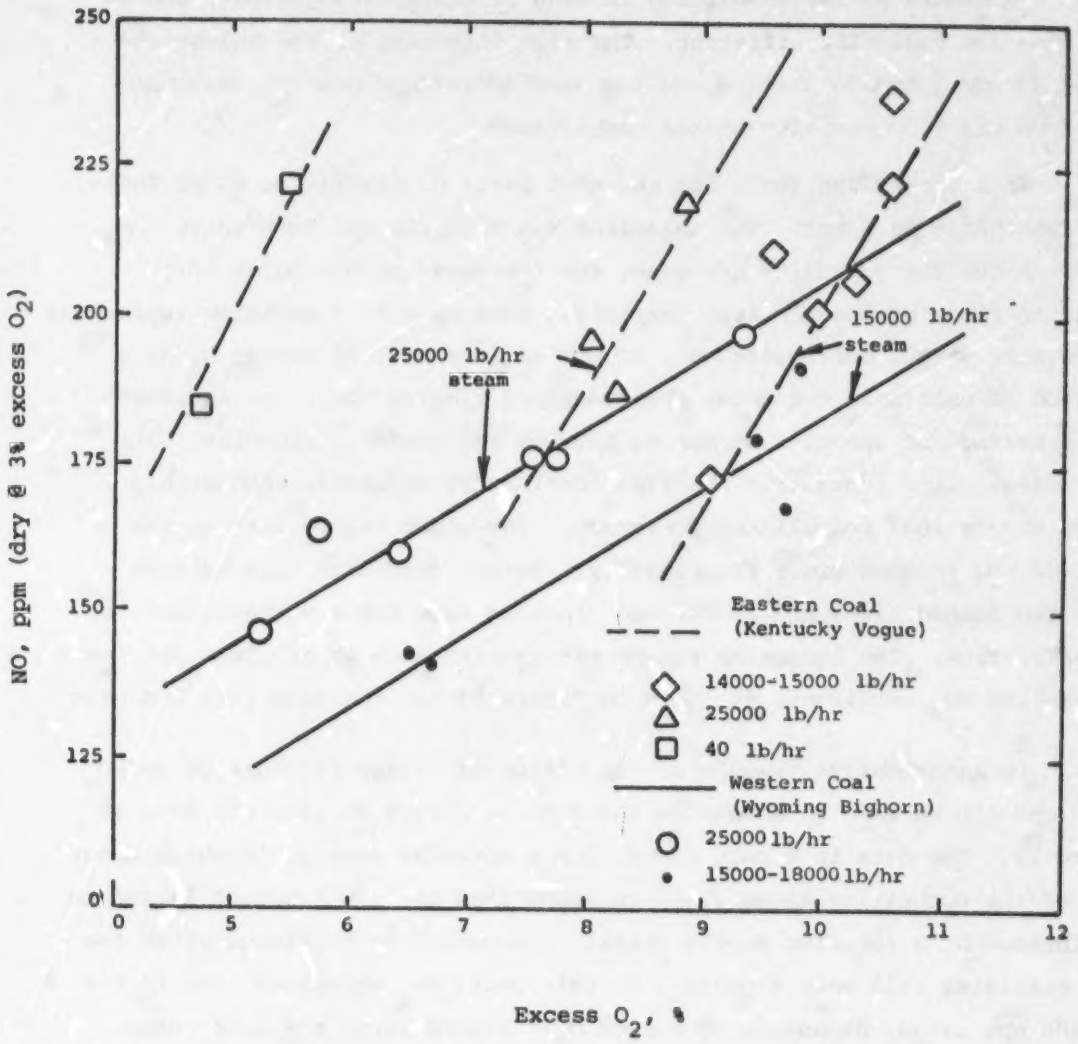


Figure 24. Water-cooled vibrating grate stoker, 45,000 lb/hr steam. Comparison of nitric oxide emissions from western and eastern coal.

Other factors considered when choosing a stoker design are listed below:

- flexibility with regard to coal type and size
- turndown ratio
- unit size/steam demand
- efficiency

For example, it is factors such as these that dictate the use of a spreader stoker furnace instead of an underfed stoker for applications above about 50000 lb/hr steam. The spreader stoker has excellent turndown ratio characteristics, can burn a wide range of fuel from municipal waste to coal, and is more efficient than the underfed stoker. The older stoker designs such as the traveling grate and underfed stokers cannot develop the heat release rates necessary for the larger industrial boilers. For these reasons a stoker type cannot be chosen merely on the basis of its NO_x emissions.

3.11 THERMAL DeNO$_x$ PROCESS*

A recent development which has performed successfully in commercial demonstrations is the Thermal DeNO$_x$ Process (Ref. 18). Ammonia (NH_3) is injected into the combustion products at a point where their temperature is 1750 $\pm$ 50 °F. Despite the presence of large quantities of O_2, the NO is a more powerful oxidizer and a large percentage of the NH_3 reacts with NO:

$$4\ NH_3 + 6\ NO \rightarrow 5\ N_2 + 6\ H_2O\ .$$

A competing reaction which uses some of the NH_3 is

$$4\ NH_3 + 3\ O_2 \rightarrow 2\ N_2 + 6\ H_2O.$$

However, under favorable conditions (optimum temperature, good mixing, low ratio of NH_3 to NO), tests indicate that from 50 to nearly 100% of the ammonia molecules react with NO molecules.

*Patented processes of Exxon Corporation

If the temperature of the combustion products is lower than optimum, a small amount of hydrogen (not enough to appreciably raise the temperature) can be injected with the ammonia. This has a beneficial effect in that it lowers the temperature at which optimum NO_x destruction takes place. However, it is of course less costly to inject pure ammonia where the temperature is at its optimum. A moving injector (similar to a traversing sootblower) with a thermocouple attached might be most suitable for this process.

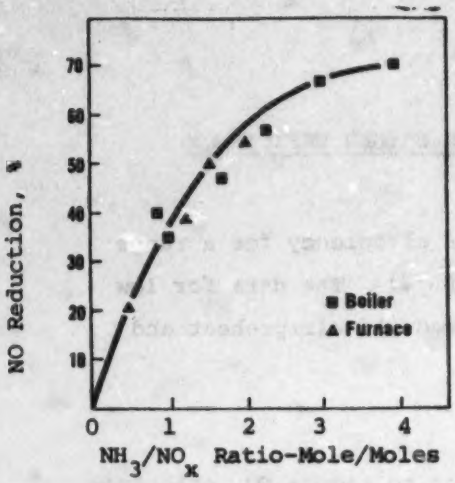
If the temperature is too high, the ammonia acts like other nitrogen-bearing fuels: NO_x is formed rather than destroyed. If the temperature is too low, the ammonia does not react and is emitted to the atmosphere.

The Thermal $DeNO_x$ Process was first demonstrated commercially in a refinery boiler in Japan in 1974. Results are shown in Figure 25. The process has since been used in several other boilers in that country. There has as yet been no commercial demonstration in the U.S.

The only potential problem seen thus far is possible cold-end corrosion due to formation of ammonium bisulfate when the Thermal $DeNO_x$ Process is used with sulfur-bearing fuels. Ammonium bisulfate is a corrosive liquid in the temperature range 400-500 °F. To date, however, there is apparently no confirmation that such a problem occurs.

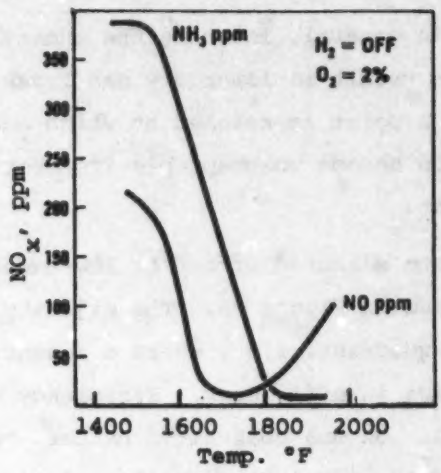
For a normal retrofit application the cost of the Thermal $DeNO_x$ Process was estimated by Exxon Research and Engineering Company to be 7-15¢ per million Btu fired (Ref. 18).

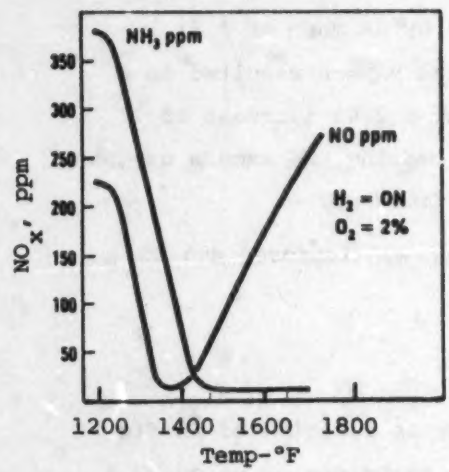
An obvious advantage to the process is that modifications of the boiler's main combustion process are not necessary. However, for boilers with high firing rates it is still desirable to minimize NO_x production in the furnace in order to minimize the cost of the ammonia and hydrogen used.



a) Up to 70% reduction in NO_x emissions was achieved in a Kawasaki refinery boiler in 1974.

b) NO_x versus temperature without hydrogen injection





c) NO_x versus temperature with hydrogen injection.

Figure 25. Results for the Thermal DeNO_x Process.

SECTION 4.0

IMPACT OF THE COMBUSTION MODIFICATIONS ON BOILER EFFICIENCY

Trade-offs between NO_x emissions and boiler efficiency for a range of combustion modifications have been examined (Ref. 2). The data for low excess air, overfire air, burners out of service, reduced air preheat and flue gas recirculation are presented below.

4.1 EFFECT OF EXCESS AIR

In general, lowering the excess air in order to reduce NO_x emissions will also result in lower dry gas losses and improved unit efficiencies. However, a point is reached at which combustible losses in the form of CO and carbon become unacceptable from both an emissions and an efficiency standpoint.

The measured effect of low-excess-air firing on boiler efficiency is illustrated in Figure 26. The majority of the data points are located in the best quadrant, i.e., where a reduction in emissions is accompanied by an increase in efficiency. Efficiency was bettered by as much as 2.5% in two cases. On one coal-fired boiler, reducing excess oxygen resulted in a 44% reduction in nitrogen oxide emissions along with a 2.0% increase of boiler efficiency. In three cases with gas fuel, lowering the excess oxygen resulted in an increase in emissions at a higher efficiency.

The efficiency of most of the boilers tested was improved and NO_x was reduced as the excess oxygen was reduced.

4.2 EFFECT OF STAGED AIR

The effect of NO_x ports on boiler efficiency is illustrated in Figure 27. Generally, the reduction of nitrogen oxide emissions by using NO_x ports had an adverse effect on efficiency. This behavior was to be expected since NO_x ports normally requires that the level of excess oxygen be maintained at higher than baseline levels to assure complete combustion.

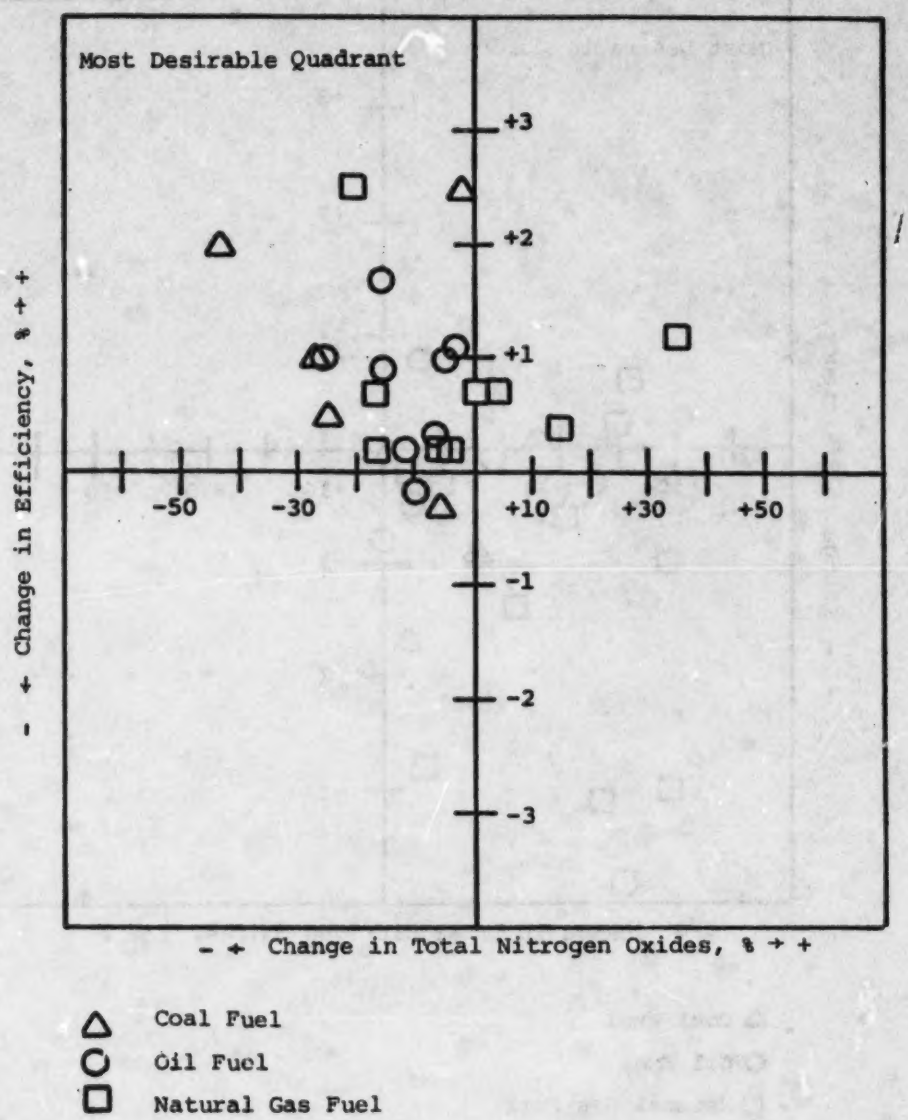


Figure 26. Effect of reducing the excess combustion air on boiler efficiency.

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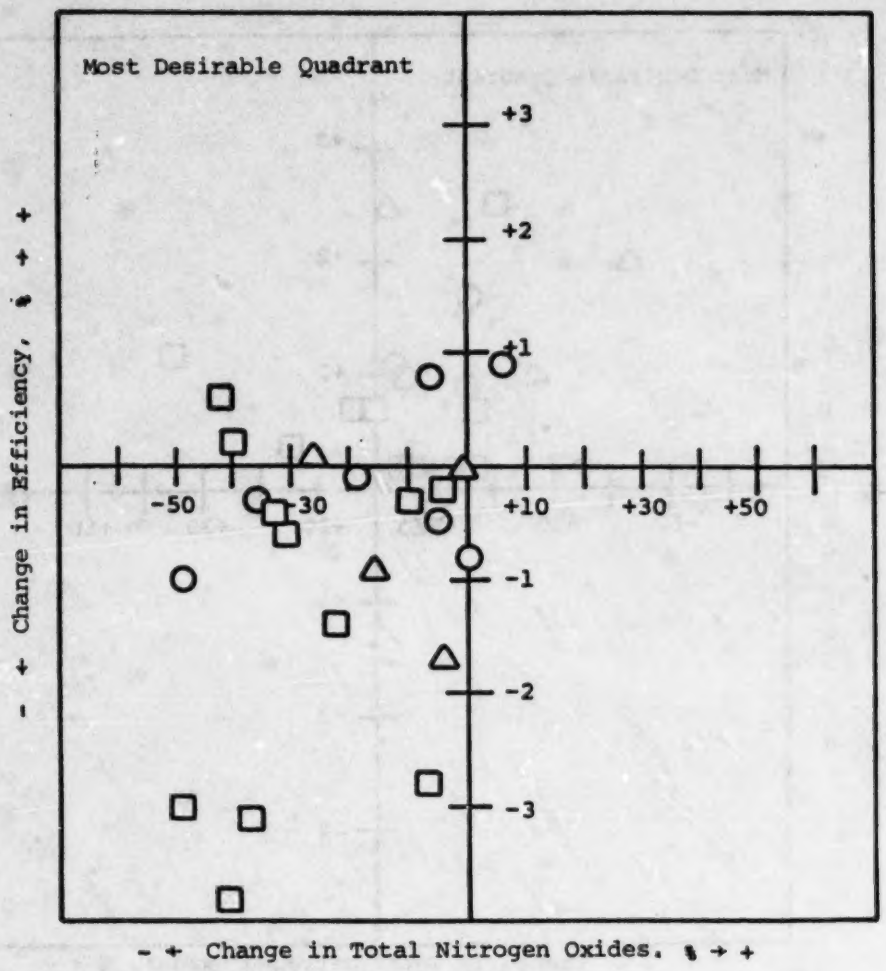

Figure 27. Effect of NO_x ports on boiler efficiency.

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This greater quantity of heated air being exhausted through the stack contributes significantly to the lowering of unit efficiency. When excess O_2 is kept constant, staged combustion can increase efficiency slightly.

A few boilers exhibited increases in efficiency when staged air was used. These boilers had staged air ports which were part of the original boiler design and were therefore more appropriately sized and located; excess O_2 could be kept low.

Figure 28 presents the effect which taking burners out of service has on boiler efficiency. The efficiency changes were generally small, 0.6% or less, but were mostly in the positive direction. One would expect the effect of burners out of service to be similar to that of NO_x ports since both techniques involve staging combustion. The quantity of test data from burners out of service on industrial boilers is small, making it difficult to draw any concrete conclusions.

4.3 EFFECT OF COMBUSTION AIR TEMPERATURE

The effect of varying the combustion air preheat temperature is shown in Figure 29. As expected, lowering the temperature to reduce emissions resulted in a degradation of boiler efficiency, because a reduction in air preheat was accompanied by an increase of flue gas temperature. The tests where the efficiency increased were tests where the air temperature was raised, rather than lowered.

If reduced air preheat is to be adopted as a permanent nitrogen oxide emissions reduction technique for a particular boiler, the stack losses can be recouped by redesigning the steam side of the boiler for more heat absorption. An example of this would be the installation or enlargement of an economizer.

4.4 EFFECT OF FLUE GAS RECIRCULATION WITH AND WITHOUT STAGED COMBUSTION

The effects of flue gas recirculation on boiler efficiency are shown in Figure 30. Also illustrated are the effects of flue gas recirculation combined with staged air. Flue gas recirculation, alone, had only small

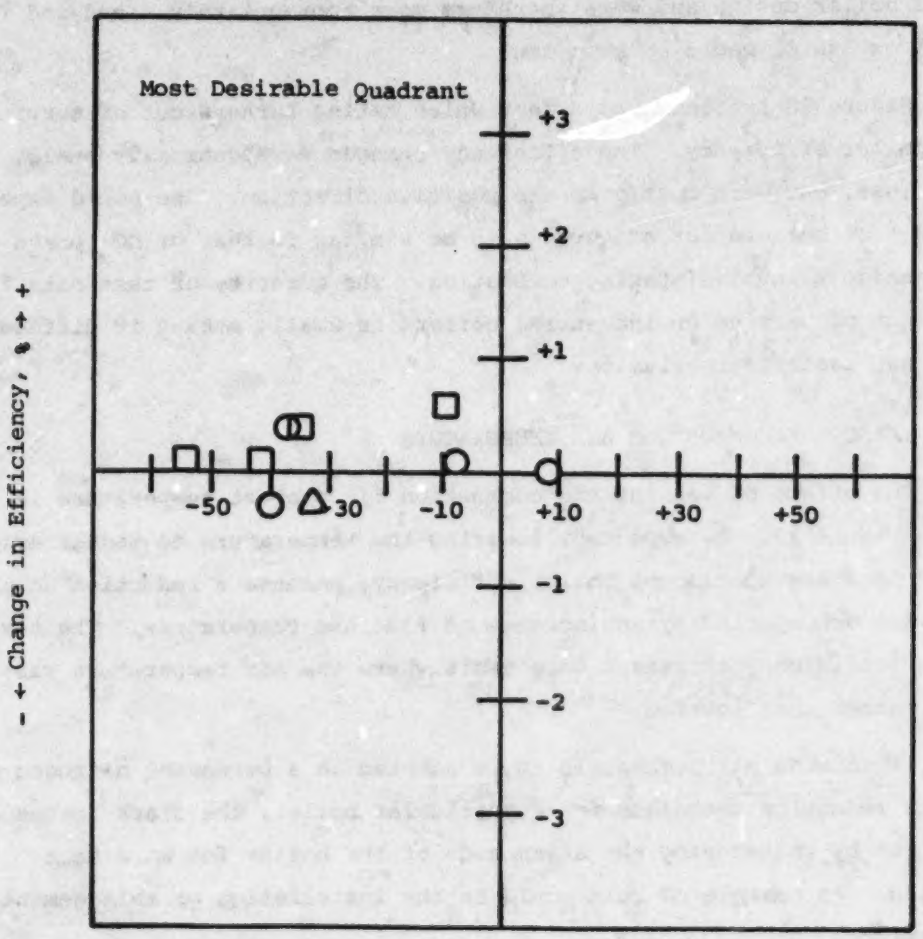

Figure 28. Effect of operating with burners out of service on boiler efficiency.

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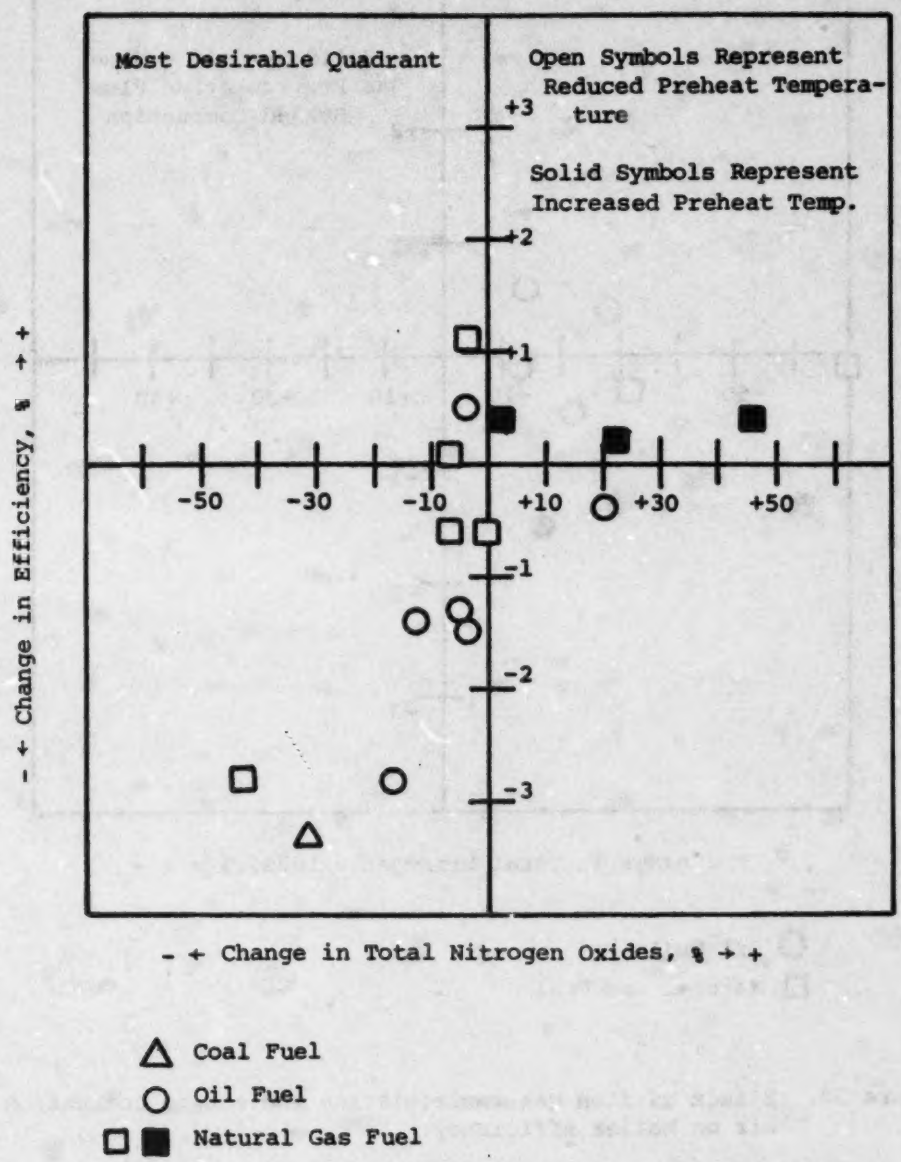

Figure 29. Effect of combustion air preheat temperature on boiler efficiency.

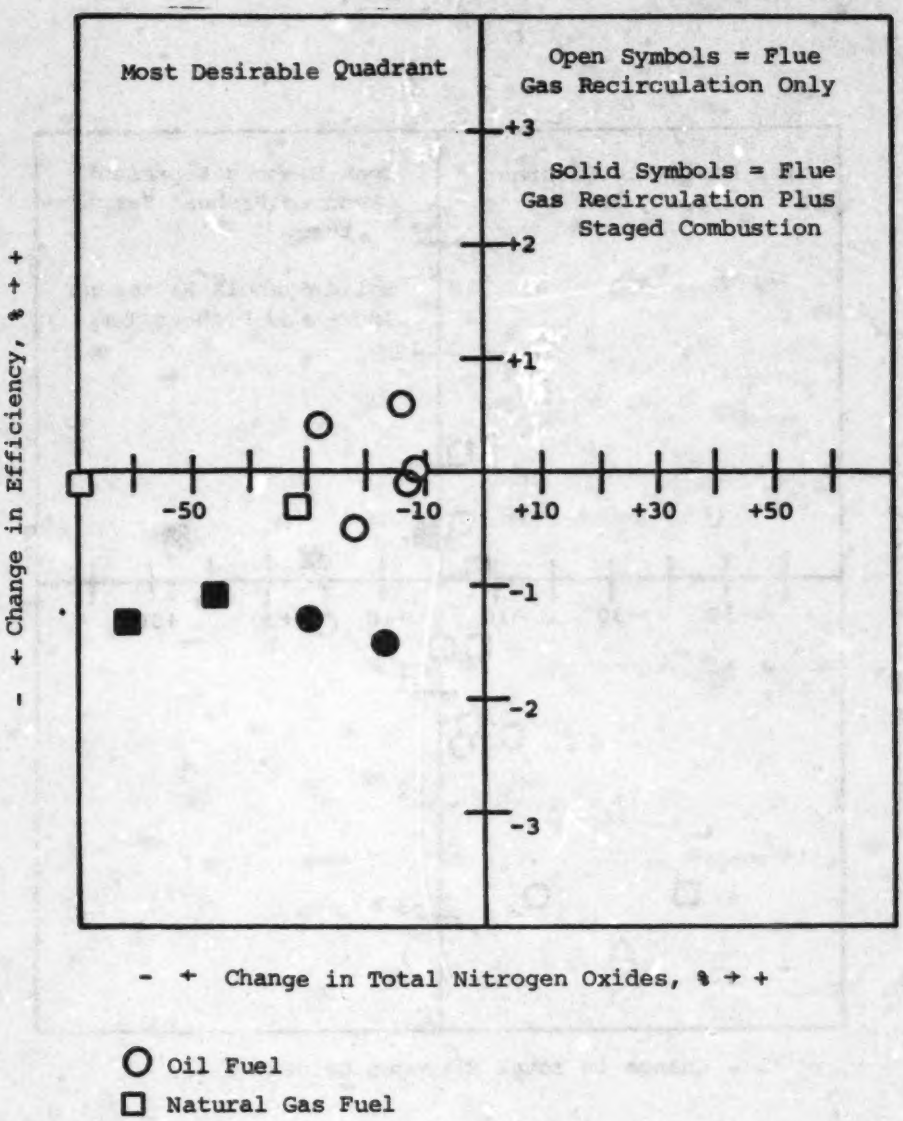

Figure 30. Effect of flue gas recirculation and staged combustion air on boiler efficiency.

effects on efficiency; however, it was quite successful in reducing NO_x on gas fuel but generally not as successful on oil. (It should be noted that the ASME boiler efficiency does not account for the auxiliary load of running the recirculating gas fan system. In some cases this added penalty in terms of total energy use may be significant.) The efficiency changes were 0.6% or less and varied from positive to negative. When staged combustion was combined with FGR, the efficiency dropped by about 1.5%, partly due to the necessary increase in the overall excess oxygen level for complete combustion.

In general, the nitrogen oxide reduction techniques of low excess oxygen firing and burners out of service resulted in boiler efficiencies equal to or better than baseline levels. NO_x ports and reduced combustion air preheat produced a degradation of efficiency. Flue gas recirculation gives a small degradation of efficiency.

SECTION 5.0

COMPARISON OF TECHNIQUES ON TWO SPECIFIC INDUSTRIAL BOILERS

Although exhaustive pilot-scale tests of combustion modifications have been carried out on a number of laboratory-scale boilers, comparisons of techniques on working industrial boilers have been comparatively rare. Two such comparisons were recently completed (Ref. 22) and the results will be summarized here. Most of the important NO_x reduction techniques were used except for the Thermal DeNO$_x$ Process.

5.1 COMBUSTION MODIFICATIONS ON A BOILER RATED AT 17,500 LB/HR OF STEAM FLOW

The boiler was a single-burner 17,500 lb/hr oil- and gas-fired watertube unit with no economizer or air preheater. The tests were run at 83% of full load. Second-stage combustion air was injected through four steel lances which were inserted through the windbox and the refractory firing face. Flue gas was withdrawn from the base of the stack and was added to the burner air through wide slots just upstream of the throat.

Baseline emissions of NO_x (corrected to 3% excess O_2, dry) were:

Fuel	NO_x, ppm (dry)
Natural gas (Ring burner)	96
(Gun burner)	92
No. 2 oil (less than 0.01% N)	110
No. 6 oil (0.20% N)	221

Oil atomization was by high-pressure (28 psig) air. A gas ring normally used for natural gas injection was found to be unstable with the particular flue-gas recirculation pattern used. Therefore a gas gun was used, rather than a ring, for most of the gas fuel tests.

The percentage reductions in NO_x are shown in Table 2 and the resulting changes in efficiency are given in Table 3. The No. 2 oil results are unusual in that a 68% NO_x reduction was achieved with flue gas recirculation alone. This may be because the high-intensity mixing and atomization by the air atomizer, and the relatively high volatility and low nitrogen content of the fuel, combined to give a gas-like flame.

It was noted that boiler efficiency was reduced by flue-gas recirculation even though no increase in excess O_2 was necessary. This was because the average temperature the combustion process was reduced, lowering the temperature-difference potential for heat transfer. The flow per unit area increased, tending to increase heat transfer, but the reduced temperature difference resulted in a greater offsetting tendency for reduced heat transfer.

The results, shown in Tables 2 and 3, were achieved with CO concentrations of less than 500 ppmV and particulates emissions of less than 0.10 lb/million Btu.

5.2 COMBUSTION MODIFICATION ON A BOILER RATED AT 45,000 LB/HR OF STEAM FLOW

The boiler was a single-burner oil- and gas-fired packaged watertube unit rated at 45,000 lb per hour of steam flow. The rated heat input was about 55×10^6 Btu/hr. This unit was equipped with an air preheater providing a combustion air temperature of up to 350 °F.

This boiler was modified to provide ten ports in the furnace side walls, five on each side, for introduction of staged combustion air. The configuration of the ports was previously shown in Figure 2. Staged air at ambient temperature was provided by a separate fan. Therefore the staged air was not preheated. The air preheater for combustion air had provision for bypass of combustion air around the preheater so that combustion air temperature could be varied.

TABLE 2. SUMMARY OF NO_x REDUCTION AS A FUNCTION OF COMBUSTION MODIFICATION TECHNIQUE FOR VARIOUS FUELS -- LOCATION 19

	Natural Gas		No. 2 Oil	No. 6 Oil
	Ring	Gun	(0.00% N)	(0.20% N)
Baseline NOx, ppmV	96	92	110	221
Combustion Modification Technique	NO_x Reduction, Percent of Baseline			
Lowered O_2	19 *	3.3	20	30
Staged Combustion Air, Normal O_2	32	46	30	29
Staged Combustion Air, Low O_2	42	--	44	42
Flue Gas Recirculation, Normal O_2	--	77	68	11
Flue Gas Recirculation, Low O_2	--	79	73	40
FGR + SCA, Normal O_2	--	76	69	53
FGR + SCA, Low O_2	--	†	77	55

* Reduction occurred at increased O_2 level in this case.

† Stability limits prevented lowering O_2.

TABLE 3. SUMMARY OF CHANGE IN BOILER EFFICIENCY DUE TO COMBUSTION MODIFICATIONS LOCATION 19

Boiler Operating Mode	Natural Gas		No. 2 Oil	No. 6 Oil
	Ring*	Gun†		
Baseline efficiency	78.2	82.6	82.5	82.5
Low O_2	- 1.2	+ 0.9	+ 1.5%	+ 1.5%
Staged Combustion Air, Normal O_2	+ 0.1	+ 0.3	+ 0.9%	+ 0.1%
Staged Combustion Air, Low O_2	+ 0.5	---	+ 1.1%	+ 0.8%
FGR, Normal O_2	---	- 0.8	- 1.9%	- 0.7%
FGR, Low O_2	---	- 0.4	+ 0.9%	+ 0.6%
FGR + SCA, Normal O_2	---	- 0.5	- 1.2%	- 0.8%
FGR + SCA, Low O_2	(Note 1)		- 0.8%	+ 0.1%

* Standard ring burner

† Optimized gas gun

NOTE (1): Unable to lower O_2 due to stability limits.

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Baseline emissions of NO_x (corrected to 3% excess O_2, dry) were as follows:

Fuel	NO_x, ppm (dry)
Natural gas	161
No. 6 oil (0.31%N)	286

The effect of each combustion modification on both NO_x emissions and boiler efficiency is compared in Table 4. This comparison shows that lowered oxygen was more effective for NO_x reduction with No. 6 oil while lowered air preheat was more effective with natural gas. Lowered oxygen level increased efficiency slightly for both fuels. Lowered air preheat reduced efficiency by 1% with gas and 2.8% with oil. Staged combustion at normal oxygen was equally effective for both fuels with only slight changes in efficiency. Staged combustion with low excess oxygen produced the largest NO_x reduction observed with No. 6 oil. A maximum reduction in NO_x of 70% was achieved with natural gas by the use of lowered air preheat in combination with staged combustion. However, this change resulted in a reduction in efficiency of 3.2%.

5.3 CONCLUSIONS

Reductions in NO_x emissions of between 70% and 80% with natural gas fuel were observed for the two modified industrial boilers tested. These reductions resulted in NO_x emission levels of between 20 and 50 ppm at 3% O_2, dry, and were achieved with the use of various combined combustion modifications including lowered excess air, staged combustion, lowered combustion air preheat, and flue gas recirculation. With the exception of lowered air preheat, these reductions were achieved with only slight changes in efficiency and no apparent detrimental changes in other emissions. With lowered air preheat, efficiency was reduced about 3%.

On the one boiler tested with No. 2 oil, NO_x reductions of about 75% were observed with the use of flue gas recirculation and reduced excess air. This reduction resulted in NO_x levels of the order of 25 ppm at 3% O_2, dry, and was obtained with an increase in efficiency of about 1% (neglecting fan power requirements).

TABLE 4. NO_x REDUCTION AND EFFICIENCY CHANGE FOR COMBUSTION MODIFICATION TECHNIQUES TESTED AT LOCATION 38

	Natural Gas	No. 6 Oil (0.31%N) [a]
Baseline NO_x, ppmV at 3% O_2	161	286
Combustion Modification Technique	NO_x Reduction, Percent of Baseline	
Lowered O_2	6	21
Lowered Air Preheat (LAP)	24	9
Staged Combustion Air (SCA), Normal O_2	31	33
SCA, Low O_2	--	42
LAP + SCA	70	--
Baseline efficiency, %	81.2	84.8
Combustion Modification Technique	Change in Efficiency, Percent	
Lowered O_2	+0.2	+0.8
LAP	-1.0	-2.8
SCA	-0.4	+0.2
LAP + SCA	-3.2	--

[a] Fuel oil nitrogen content, percent by weight.

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Reductions in NO_x with No. 6 oil were not as dramatic as for the other fuels. However, it was significant that a 55% reduction could be achieved with the use of combined flue gas recirculation, staged combustion, and lowered excess air. It is believed that reductions of this magnitude have not been achieved previously with the heavier fuels of the No. 6 type.

The use of flue gas recirculation can result in flame instability but it was found that these problems could be resolved by relocating the fuel injection point to areas where flue gas is not fully mixed with air. This technique requires that the flue gas be only partially mixed (and stratified) in the burner throat as opposed to the more common method of complete mixing in the windbox.

The degree of the NO_x reductions achieved with natural gas and oil fuels is very encouraging for the prospects of controlling NO_x emissions from industrial size boilers. However, the differences between the two boilers tested in NO_x emissions and reductions achieved indicate that important unit-to-unit variations exist in terms of the relative effectiveness of these NO_x control methods. Therefore, the specific reductions obtained should not be interpreted as achievable on all industrial boilers.

SECTION 6.0

COST OF THE CONTROL TECHNIQUES

Building an industrial boiler which incorporates modified combustion techniques involves considerations of control, compactness, and customer acceptance which are beyond the scope of this report. It is not practical to give plausible estimates of the cost of equipment needed to achieve a certain result on the wide variety of industrial boiler types. However, some order-of-magnitude estimates of the cost per unit reduction for comparison of various techniques have been made (Ref. 19) and will be reviewed as a general guide.

The cost components are shown in Table 5. The first term represents the size-independent or fixed capital costs for such things as design, instrumentation, etc. while the second term represents the size-dependent capital costs such as for equipment, installation, etc. These two capital costs are annualized at a uniform 20% per year. The third term represents the operating costs, which depend on the boiler size and the operating hours per year and accounts for fuel penalties or savings, as well as power or chemical consumption for the control. The denominator represents the emission reduction which depends on the boiler size, its emission factor, the reduction factor for the control, and the annual operating hours. For very small boilers the first term dominates and the cost/reduction ratio rises in inverse proportion to the device size. For very large devices or controls with high operational costs, the third term dominates and the cost/reduction ratio asymptotes to a value independent of either device size or operating hours per year.

TABLE 5. APPROACH TO NO_x CONTROL COSTS

$$\text{COST/REDUCTION} = \frac{A + BQ + CQT}{QFRT} = \frac{\$}{\text{TON}}$$

A = Size Independent Annualized Capital Cost, $

BQ = Size Dependent Annualized Capital Cost, $

CQT = Annual Operating Costs: Size, Time Dependent, $

Q = Heat Input Rate, 10^6 Btu/hr

F = NO_x Emission Factor, Tons $NO_x/10^6$ Btu

R = Fractional NO_x Reduction by Control Method

T = Annual Operating Time, Hr/Year

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In developing cost data with which to compare costs on a generalized basis, rather than for a specific combustion device, one is forced to deal with only the generic costs. Unusual site-specific or application-specific costs cannot be readily factored in.

Table 6 shows estimated cost/reduction ratios for NO_x control by each of the options mentioned earlier plus an additional one, reburnering with "low-NO_x burners." Capital costs were annualized at 20% per year. Operating time was assumed to 6000 hr/year, and fuel cost to be \$2.00/10^6 Btu.

Lowering excess air by 10%, in those applications where present operation permits such a reduction, results in a cost/reduction ratio of over \$1800/ton of NO_x (as NO_2) reduced for devices smaller than 10×10^6 Btu/hr. This was estimated assuming that the excess O_2 could be lowered by 2%, with a reduction of 30 ppmV (about 0.04 lb/10^6 Btu) in NO_x emissions. Oxygen instrumentation, its installation and checkout were assumed to cost \$8,500 per unit. Because low-O_2 operation results in reduced fuel use, the initial fixed costs for instrumentation and burner adjustments become comparatively smaller for larger boilers.

For staged combustion a minimum capital cost for setup on small units was assumed to be \$10,000. For a 50×10^6 Btu/hr boiler a capital cost of \$30,000 was assumed. A 1/4% loss in fuel efficiency, and a 33% reduction from an initial emission rate of 0.3 lb NO_x (as NO_2)/10^6 Btu were used for the calculations. For a 50×10^6 Btu/hr boiler, then, the cost/reduction ratio CE would be

$$CE = \frac{(0.2)(\$30{,}000)/yr + (6{,}000\ hr/yr)(0.0025)(\$2/10^6\ Btu)(50 \times 10^6\ Btu/hr)}{(50 \times 10^6\ Btu/hr)(0.1\ lb/10^6\ Btu)(6{,}000\ hr)}$$

$$= \$0.25/lb \text{ or } \$500/ton.$$

For staged combustion the cost/reduction ratio drops sharply for larger sizes as the fixed costs for implementing this mode are divided by larger emissions reductions. Opportunities for cost ratios as low as shown for the largest boilers are primarily limited, however, to those with forced draft, multiple burners, and air preheat.

TABLE 6. COSTS OF NO_x CONTROL BY COMBUSTION MODIFICATION (Ref. 19)

(Units of \$/Ton NO_2 Prevented)

Control Option \ Firing Rate Million Btu/Hr	10	100	1000
Low Excess Air (-10%)	1800	300	-300
Staged Combustion (25%)	1000	300	100
Flue Gas Recirculation (20%)	2300	900	700
Reduced Air Preheat (-100 °F)	1650	1580	1500
Water Injection (1 lb/lb)	2500	2200	2000
Ammonia Injection (90%)	1000	390	370
Reburnering - Low NO_x Burners	800-1000	450-550	200-300

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The minimum cost of installing a flue gas recirculation system on a small boiler was assumed to be $30,000. A fuel efficiency decrement of 1% and a 40% NO_x reduction from an initial level of 0.3 lb/10^6 Btu were used. For larger boilers the capital cost was taken to be $1000/$10^6$ Btu, so that for a 100 x 10^6 Btu/hr ratio the cost effectiveness ratio was

$$CE = \frac{(0.2/yr)(\$100,000) + (6,000\ hr/yr)(0.1)(\$2/10^6\ Btu)(100 \times 10^6\ Btu/hr)}{(100 \times 10^6\ Btu/hr)(0.2\ lb/10^6\ Btu)(0.4)(6000\ hr/yr)}$$

$$= \$0.44/lb \text{ or } \$890/ton$$

The asymptotic cost/reduction ratio at large size stays higher than for staged combustion because of the efficiency penalty that it causes.

Reduced air preheat and water injection have comparatively low capital costs but comparatively high operational costs, resulting in a uniformly high cost/reduction ratio for all sizes.

Water injection has the highest cost per ton of NO_x reduced for all boiler sizes and is therefore not considered as a practical technique in view of the other options available.

The Thermal DeNO_x Process injection is seen to have attractive cost/reduction ratios for all sizes, leveling off beyond that size where a minimum installation cost dominates. At sizes 100 x 10^6 Btu/hr or larger the costs are dominated by the chemical costs. The costs shown are for $200/ton of ammonia delivered on site. Other costs are based on proprietary data. Lest one jump to the conclusion that this is the universal cost-effective solution, it must be pointed out that not all combustion devices are configured to provide access for the injection at the proper temperatures or to provide the subsequent mixing and reacting zone required.

The final NO_x control costed is that of reburnering with "low-NO_x burners." The unit costs shown here are seen to be attractive compared with the other alternatives--but again the range of applicability has limitations. For this option the costs are almost totally for hardware, installation, adjustment, and checkout with negligible operating costs. The major variable in the costs is the degree of change of burner controls, igniters, and flame detectors necessitated by the new burners. A NO_x reduction of 60 ppmV (0.08 lb/10^6 Btu) was assumed.

SECTION 7.0

SUMMARY

Field tests and laboratory studies indicate that the most promising techniques for oxides of nitrogen control from industrial-sized boilers include:

- reduced excess air levels
- staged combustion
- reduced air preheat
- flue gas recirculation (gas and oil fuels only)
- burner redesign and adjustments
- Thermal DeNO$_x$ Process

Table 7 is a summary of these specific techniques and others, indicating their applicability for NO$_x$ control on boilers firing natural gas, fuel oil, and coal.

On the basis of the results of the field measurements reported, it appears to be possible and practical to reduce the total nitrogen oxides emissions by up to 50% with certain selected combustion modification methods which are appropriate for the particular unit design. However, with only two of the methods is the boiler efficiency unimpaired: excess air reduction, and burner-out-of-service.

The burner-out-of-service modification is not as attractive as reduction of excess air because there is generally a penalty in the maximum load that is possible unless the in-service burners are enlarged to handle the increased fuel flow.

Industrial boilers exhibit a large amount of variability from boiler to boiler in terms of both design and operating characteristics. Thus, a given industrial boiler may respond in a totally different manner compared to another

TABLE 7. SUMMARY OF NO_x REDUCTION TECHNIQUES

COMBUSTION MODIFICATION	MECHANISM OF NO_x REDUCTION	OPERATIONAL EXPERIENCE		GENERAL APPLICABILITY	IMPACT ON UNIT EFFICIENCY
		GENERAL TRENDS	EFFECT OF FUEL TYPE		
Excess air level	Varies the overall fuel/air mixture ratio	o For high-nitrogen fuels, NO_x emissions decrease with decreasing excess air level.	o Excess air level has the greatest effect on coal, followed by No. 6 and 5, then No. 2 fuel oil. Little effect is seen with natural gas.	Feasible modification for both new and retrofit.	o Improves efficiency due to lower dry gas losses
Staged Combustion	Creates local fuel/air ratio stratification by bypassing air from the burner(s). Burners-Out-of Service: Fuel flow stopped to selected burners. NO_x Ports: Special ports provided for air addition downstream of the burner.	o NO_x emissions decrease as the air/fuel ratio at the burner is decreased o Successful application of these techniques requires sufficient test time to empirically determine boiler adjustments and burner patterns to allow operation at low overall excess O_2 with a burner out of service.	o For fuel oil, conversion of fuel nitrogen to NO_x is reduced by staged combustion. Nitrogen conversion can be reduced to the range of 20 to 30% compared with normal levels of 40% to 50%. Thermal NO_x is also reduced for all fuels.	Burners-Out-of-Service Applicable only to multiple-burner boilers. Not applicable to stoker-fired units.	o Often lowers efficiency since increased excess O_2 levels must be used to prevent smoke
Air register adjustment	Controls the swirl level and local rate of fuel/air mixing	o NO_x emissions decrease as swirl is decreased	o Effects similar for all fuels		o Little effect on efficiency
Atomization technique	Controls fuel/air mixing rates	o When properly atomized, the type of oil atomizer had little effect on NO_x emissions (air steam, or mechanical)	o Only applicable to oil-fired units	Tip changes on existing units feasible	o Efficiency will improve if lower excess O_2 operation results from better atomization

TABLE 7. Continued

COMBUSTION MODIFICATION	MECHANISM OF NO_x REDUCTION	OPERATIONAL EXPERIENCE		GENERAL APPLICABILITY	IMPACT ON UNIT EFFICIENCY
		GENERAL TRENDS	EFFECT OF FUEL TYPE		
Combustion air temperature decrease	Decreased combustion air temperature decreases peak gas temperatures	o NO_x emissions decrease with decreasing combustion air temperature. o NO_x emissions for larger burners seem to decrease at a greater rate with decreasing air temperature than for smaller burners.	o Effect is mainly seen on natural gas-fired boilers, not an important consideration for oil and coal-fired units.	Air preheat presently used only on the larger industrial boilers	o Lowers unit efficiency
Firing rate (% load)	Affects the heat release rate per unit volume in the furnace and the heat transfer rates	o Little effect of firing rate on NO_x emissions on units without air preheat. o With air preheat, NO_x emissions increase with firing rate.	o Effects similar for all fuels.		
Flue gas recirculation (FGR)	Reduces peak gas temperatures and O_2 concentrations by adding combustion products to the combustion air (diluents)	o NO_x emissions decrease as the amount of FGR increases o Greatest reductions occur with first 10% recirculated.	o Greatest reductions for natural-gas-fired units which involve all "thermal NO_x" o FGR does not greatly affect conversion of fuel nitrogen to NO_x	Little field experience with industrial boilers available. Feasible for new boilers, moderately difficult for existing units.	o Lowers overall efficiency due to extra fan power and increased stack gas temperature.
Burner heat release rate (Btu/hr/burner)	Affects local combustion rates and gas heat transfer rates in the furnace	o NO_x emissions increase with increased burner loading	o For natural gas, the NO_x relationship depends on the combustion air temperature; the higher the air temperature, the more important the burner loading.	Applicable to multiple burner units.	
Fuel type change	Reduces fuel-bound nitrogen content	o NO_x emissions increase with increasing fuel nitrogen content. o The average conversion of fuel nitrogen to NO_x is typically 40% for fuel oils.	o Not applicable to gas fuels (except in some waste fuel streams.)	Depends on suitability and costs of the fuels due to constraints on availability of fuels. Not a generally applicable technique.	
Boiler tune-up	Assures performance according to design specifications	o NO_x can increase or decrease following a boiler tune-up depending on the "as found" condition	o Effect similar for all fuels.		o Should improve efficiency
Thermal deNO_x	Selective non-catalytic reaction	o Reduction of NO_x when correct amount of NH_3 or H_2 is used	o None known to date.	Experience limited.	o None, but more expensive "fuels" (NH_3, H_2) are used.

boiler when a particular NO_x reduction technique is used. Thus while overall trends can be illuminating with regard to NO_x reductions to be expected, each unit should be examined individually in terms of its design characteristics and the choice of NO_x reduction techniques to be applied. It is also true that boiler designs may limit the type of combustion modification that is applicable to certain boiler types. For example, sufficient furnace space may not be available for staged combustion implementation.

7.1 EXCESS AIR

In order to operate industrial boilers at lower excess air levels the designer should provide controls, alarms, and combustion quality monitors of the type that are used to operate utility boilers. Recent advances in instrumentation technology make combustion monitors very reliable. Dependable in-situ O_2 analyses can be made using the solid state ZrO_2 monitor. These systems have inherently low maintenance requirements. The closer control necessary with reduced excess air operation probably precludes boiler operation by hand, as most industrial boilers are operated; therefore, the controls should be automatic, again following the lead of the utility boiler control designs. Projected future fuel costs make these control systems more attractive because of their fuel savings as well as pollution reduction potential.

7.2 STAGED COMBUSTION

Staged combustion can be an effective means of reducing NO_x emissions; however, this modification requires extra air passages and fans in addition to the combustion controls discussed under the low excess air section. In some cases, staging the combustion air works at cross purposes to low excess air firing since the overall excess air must be increased to control combustible losses.

7.3 AIR PREHEAT

Reducing the combustion air preheat temperature as a method of NO_x control on existing units can only be considered as a last-resort measure due to the large efficiency penalties involved. New boilers would have to be redesigned to recover most of the excess flue gas enthalpy involved if no preheat were used in future designs. Presently, few industrial size boilers use preheated air.

7.4 FLUE GAS RECIRCULATION

The use of FGR on gas fuel is a very effective NO_x reduction technique and can be coupled with staged combustion and low excess air to substantially reduce NO_x emissions. The effectiveness is more limited on oil fuel and very limited with coal. FGR use does not come without penalties since an additional high-temperature fan and duct work are required. Typically, a unit will be more sensitive to overall excess O_2 and its smoke level will be reduced while using FGR.

7.5 BURNER DESIGN AND ADJUSTMENTS

Improvements in thermal efficiency as well as reduced pollutant emissions can be obtained by proper maintenance of burners if, for example, the overall excess O_2 can be lowered by improved fuel/air mixing. New burner designs are available which advertise low emission operation as well as versatile operation. These new designs should be considered when a unit retrofit is anticipated.

7.6 THERMAL DeNO$_x$ PROCESS

This process involves injection of ammonia into combustion products at a point where the temperature is 1750 $\pm$ 50 °F. The ammonia reacts with NO, reducing NO_x emissions. Although insufficient operating experience with this process has been accumulated to date, it may prove to be the most suitable technique for industrial boilers. It is apparently not sensitive to fuel or boiler characteristics, and to a certain extent is "tunable" to suit individual boiler characteristics and local regulations. The equipment needed apparently is simple, with low initial cost, and the operating expense is reasonable. In order to minimize the operating expense, however, it is desirable that NO_x production in the furnace be relatively low.

7.7 LIMITATIONS ON APPLYING NO_x CONTROLS

Any modification or redesign of a boiler to incorporate controls for NO_x can affect the combustion process in a way that causes significant increases in other pollutants. Monitoring and control of carbon monoxide, unburned hydrocarbons, particulates, smoke, and opacity must be an integral part of any program to control NO_x. In addition, it is necessary to evaluate flame scanner performance, flame stability, steam temperature, and load-following performance. Long term effects on tube life and corrosion should also be monitored. Each of these problems will not necessarily occur on every boiler. However, it is important to be aware of the potential occurrence and to establish limits for NO_x control based on adequate margin to avoid such problems.

SECTION 8.0

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SECTION 9.0

CONVERSION FACTORS

SI UNITS TO METRIC OR ENGLISH UNITS

To Obtain	From	Multiply By
g/Mcal	ng/J	0.004186
10^6 Btu	GJ	0.948
MBH/ft^2	GJ·hr^{-1}·m^{-2}	0.08806
MBH/ft^3	GJ·hr^{-1}·m^{-3}	0.02684
Btu	gm cal	3.9685×10^{-3}
10^3 lb/hr* or MBH	GJ/hr	0.948
lb/MBtu	ng/J	0.00233
ft	m	3.281
in	cm	0.3937
ft^2	m^2	10.764
ft^3	m^3	35.314
lb	Kg	2.205
Fahrenheit	Celsius	$t_F = 9/5(t_c)+32$
	Kelvin	$t_F = 1.8K - 460$
psig	Pa	$P_{psig} = (P_{pa})(1.450 \times 10^{-4})-14.7$
psia	Pa	$P_{psia} = (P_{pa})(1.450 \times 10^{-4})$
iwg (39.2 °F)	Pa	$P_{iwg} = (P_{pa})(4.014 \times 10^{-3})$
10^6 Btu/hr	MW	3.413
GJ/hr	MW	3.60

To Obtain ppm, at 3% O_2 of	Multiply Concentration[♦] in ng/J by
Natural Gas Fuel	
CO	3.23
HC	5.65
NO or NOx	1.96
SO_2 or SOx	1.41
Oil Fuel	
CO	2.93
HC	5.13
NO or NOx	1.78
SO_2 or SOx	1.28
Coal Fuel	
CO	2.69
HC	4.69
NO or NOx	1.64
SO_2 or SOx	1.18

*lb/hr of equivalent saturated steam

♦conversions between ng/J and ppm are approximate and based on typical fuel compositions

ENGLISH AND METRIC UNITS TO SI UNITS

To Obtain	From	Multiply By
ng/J	lb/MBtu	430
ng/J	g/Mcal	239
GJ·hr^{-1}·m^{-2}	MBH/ft^2	11.356
GJ·hr^{-1}·m^{-3}	MBH/ft^3	37.257
GJ/hr	10^3 lb/hr* or 10^6 Btu/hr	1.055
m	ft	0.3048
cm	in	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
Kg	lb	0.4536
Celsius	Fahrenheit	$t_c = 5/9\ (t_F-32)$
Kelvin		$t_K = 5/9\ (t_F-32)\ +273$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895 \times 10^3)$
Pa	psia	$P_{pa} = (P_{psia})(6.895 \times 10^3)$
Pa	iwg (39.2°F)	$P_{pa} = (P_{iwg})(249.1)$
MW	10^6 Btu/hr	0.293
MW	GJ/hr	0.278

To Obtain ng/J of	Multiply Concentration[♦] in ppm at 3% O_2 by
Natural Gas Fuel	
CO	0.310
HC	0.177
NO or NOx (as equivalent NO_2)	0.510
SO_2 or SOx	0.709
Oil Fuel	
CO	0.341
HC	0.195
NO or NOx (as equivalent NO_2)	0.561
SO_2 or SOx	0.780
Coal Fuel	
CO	0.372
HC	0.213
NO or NOx (as equivalent NO_2)	0.611
SO_2 or SOx	0.850

APPENDIX A

EMISSION CORRECTION CALCULATIONS FOR FLUE GAS MOISTURE CONTENT

This appendix provides a procedure for correcting emission measurements to a dry basis. Some measurement systems provide for condensation and removal of moisture from the gas being sampled prior to measurement of the pollutant. Those systems give the measurement on a dry basis directly and no moisture correction is necessary. However, some pollutants, such as NO_2, SO_2, and hydrocarbons would be removed from the sample gas by moisture condensation. It is therefore necessary to measure these pollutants on a wet basis, then correct the reading to a dry basis for reporting.

Each method or instrument used for each pollutant should be examined to clearly understand whether each compound measured is being indicated on a wet basis or a dry basis. All data recording forms should record that basis.

The equation for correction of a volumetric measurement (in ppm or % by vol.) from wet to dry basis using NO_x as an example, is:

$$NO_{x,\ dry\ basis} = \frac{NO_{x,\ meas.,\ wet}}{(100 - \%\ H_2O)} \times 100 \qquad \text{(A-1)}$$

The values for $NO_{x,\ meas.,\ wet}$ and $\%\ H_2O$ should be at actual stack conditions as measured.

Use of Equation A-1 requires knowing the moisture content ($\%\ H_2O$) of the flue gas as a percentage by volume of the total gas. The EPA has provided a standard method for determining moisture content.* The moisture content of the stack gas should be measured by this method or a comparable method for most accurate results.

*Code of Federal Regulations, Title 40, Protection of Environment, Part 60, Appendix A, Reference Method 4, Determination of Moisture in Stack Gases, U.S. Government Printing Office.

When the moisture content cannot be measured, the following equation can be used to calculate moisture content:

$$\% H_2O = \frac{(20.95 - \% O_{2,\ dry}) \times 100}{(2095/A - \% O_{2,\ dry})} \qquad \text{(A-2)}$$

To use this equation, the oxygen content must be known, expressed on a dry basis. The factor "A" is a function of the fuel burned and is the percent moisture that would be present if the fuel was burned with a theoretical amount of air (zero excess air). Typical values of A are given below for common fuel types:

Fuel	A, % H_2O by Vol. at zero % O_2
Natural Gas	18.4
No. 2 Oil	12.0
No. 6 Oil	11.5
Coal	7.0

A more accurate value of A can be obtained from the ultimate analysis of the fuel, if available, by the following equation:

$$A = \frac{1.92\ (\%H)}{5.53(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)} \qquad \text{(A-3)}$$

where %H, %C, %S, %N and %O are the content by percent weight in the fuel of hydrogen, carbon, sulfur, nitrogen, and oxygen, as determined by the ultimate analysis.

When the moisture content is measured, Equations A-2 and A-3 are not needed. However, it is a good practice to use these equations anyway and compare the calculated moisture content with the measured value. If the comparison is poor, the measurement equipment should be checked for proper operation.